US ENERGY CORP

FORM 10-K
(Annual Report)

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

FORM 10-K

(Mark One)
☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 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 ☑

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Company was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ☑ NO ☐

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

Indicate by check mark if disclosure of delinquent filers, pursuant to Item 405 of Regulation S-K (§ 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 ☑

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

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," and similar terms 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.

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, causing periodic shortages. These problems can be particularly severe in certain regions such as the Williston Basin and Texas. During periods of high oil and gas prices, the demand for drilling rigs and equipment tends to increase along with increased activity levels, and this may result in shortages of equipment. Higher oil and gas prices generally stimulate increased demand for equipment and services and subsequently often result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services, and personnel in exploration, production and midstream operations. These types of shortages and subsequent price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those activities that we currently have planned and budgeted, causing us to miss our forecasts and projections.

We depend on key personnel.

Our Chief Executive Officer (one of only two employees) has experience in dealing with the acquisition of and financing of oil and gas properties. We rely extensively on third party consultants for accounting, legal, professional engineering, geophysical and geological advice in oil and gas matters. The loss of key personnel such as our Chief Executive Officer could adversely impact our business, as finding replacements could be difficult as a result of competition for experienced personnel.

Risks Related to Our Stock

We have issued shares of Series A Preferred Stock with rights superior to those of our common stock.

Our articles of incorporation authorize the issuance of up to 100,000 shares of preferred stock, $0.01 par value. Shares of preferred stock may be issued with such dividend, liquidation, voting and conversion features as may be determined by the Board of Directors without shareholder approval. Pursuant to this authority, in February 2016 we approved the designation of 50,000 shares of Series A Convertible Preferred Stock (“Series A Preferred”) in connection with the disposition of our mining segment.

The Series A Preferred accrues dividends at a rate of 12.25% per annum of the Adjusted Liquidation Preference; such dividends are not payable in cash but are accrued and compounded quarterly in arrears. The “Adjusted Liquidation Preference” is initially $40 per share of Series A Preferred for an aggregate of $2.0 million, with increases each quarter by the accrued quarterly dividend. The Series A Preferred is senior to other classes or series of shares of the Company with respect to dividend rights and rights upon liquidation. No dividend or distribution will be declared or paid on our common stock, (i) unless approved by the holders of Series A Preferred and (ii) unless and until a like dividend has been declared and paid on the Series A Preferred on an as-converted basis.

At the option of the holder, each share of Series A Preferred may initially be converted into 13.33 shares of our common stock (the “Conversion Rate”) for an aggregate of 666,667 shares. The Conversion Rate is subject to anti-dilution adjustments for stock splits, stock dividends and certain reorganization events and to price-based anti-dilution protections. Each share of Series A Preferred will be convertible into a number of shares of common stock equal to the ratio of the initial conversion value to the conversion value as adjusted for accumulated dividends multiplied by the Conversion Rate. In no event will the aggregate number of shares of common stock issued upon conversion be greater than 793,349 shares. The Series A Preferred will generally not vote with our common stock on an as-converted basis on matters put before our shareholders. The holders of the Series A Preferred have the right to require us to repurchase the Series A Preferred in connection with a change of control. The dividend, liquidation and other rights provided to holders of the Series A Preferred will make it more difficult for holders of common stock to realize value from their investment.

Future equity transactions and exercises of outstanding options or warrants could result in dilution.

From time to time, we have sold common stock, warrants, convertible preferred stock and convertible debt to investors in private placements and public offerings. These transactions caused dilution to existing shareholders. Also, from time to time, we issue options and warrants to employees, directors and third parties as incentives, with exercise prices equal to the market price at the date of issuance. During 2016, we also granted shares of restricted common stock that are subject to issuance upon future vesting events. Vesting of restricted common stock and exercise of options and warrants would result in dilution to existing shareholders. Future issuances of equity securities, or securities convertible into equity securities, would also have a dilutive effect on existing shareholders. In addition, the perception that such issuances may occur could adversely affect the market price of our common stock.

We do not intend to declare dividends on our common stock.

We do not intend to declare dividends on our common stock in the foreseeable future. Under the terms of our Series A Preferred Stock, we are prohibited from paying dividends on our common stock without the approval of the holders of the Series A Preferred Stock. Accordingly, our common shareholders must look solely to increases in the price of our common stock to realize a gain on their investment, and this may not occur.

We could implement take-over defense mechanisms that could discourage some advantageous transactions.

Although our shareholder rights plan expired in 2011, certain provisions of our governing documents and applicable law could have anti-takeover effects. For example, we are subject to a number of provisions of the Wyoming Management Stability Act, an anti-takeover statute, and have a classified or “staggered” board. We could implement additional anti-takeover defenses in the future. These existing or future defenses could prevent or discourage a potential transaction in which shareholders would receive a takeover price in excess of then-current market values, even if a majority of the shareholders support such a transaction.

Our stock price likely will continue to be volatile.

Our stock is traded on the Nasdaq Capital Market. In the two years ended December 31, 2016, our common stock has traded as high as $2.84 per share and as low as $0.11 per share. We expect our common stock will continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- price volatility in the oil and gas commodities markets;
- variations in our drilling, recompletion and operating activity;
- relatively small amounts of our common stock trading on any given day;
- additions or departures of key personnel;
- legislative and regulatory changes; and
- changes in the national and global economic outlook.

The stock market has recently experienced significant price and volume fluctuations, and oil and gas prices have declined significantly. These fluctuations have particularly affected the market prices of securities of oil and gas companies like ours.

If our common stock is delisted from the NASDAQ Capital Market, its liquidity and value could be reduced.

In order for us to maintain the listing of our shares of common stock on the NASDAQ Capital Market®, the common stock must maintain a minimum bid price of $1.00 as set forth in NASDAQ Marketplace Rule 5550(a)(2). If the closing bid price of the common stock is below $1.00 for 30 consecutive trading days, then the closing bid price of the common stock must be $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the rule. We cannot guarantee that we will be able to remain in compliance with the minimum price requirement within the grace period or satisfy other continued listing requirements. If our common stock is delisted from trading on the NASDAQ Capital Market, it may be eligible for trading over the counter, but the delisting of our common stock from NASDAQ could adversely impact the liquidity and value of our common stock. On March 27, 2017, we were given notice by the NASDAQ Capital Market that the closing price of our common stock has traded below $1.00 for 30 consecutive days. We have 180 calendar days to return to compliance.

Item 1 B - Unresolved Staff Comments.

None.

Item 2 – Properties

Oil and gas

The following table sets forth our net proved reserves as of the dates indicated. We do not have in-house geophysical or reserve engineering expertise. We therefore primarily rely on the operators of our producing wells who provide production data to our independent reserve engineers. Reserve estimates are based on average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period. Reserve estimates as of December 31, 2016, 2015 and 2014 are based on the following average prices, in each case as adjusted for transportation, quality, and basis differentials applicable to our properties on a weighted average basis:

	2016	2015	2014
Oil (per Bbl)	$ 42.75	$ 43.54	$ 85.63
Gas (per Mcfe)	$ 2.48	$ 3.36	$ 8.84

Presented below is a summary of our proved oil and gas reserve quantities as of the end of each of our last three fiscal years:

	As of December 31,								
	2016 (1)			2015 (1)			2014 (2)		
	Oil (Bbl)	Gas (Mcf)	Total (BOE)	Oil (Bbl)	Gas (Mcf)	Total (BOE)	Oil (Bbl)	Gas (Mcf)	Total (BOE)
Proved developed	657,280	1,379,170	887,142	1,248,750	2,068,190	1,593,448	1,754,668	1,892,446	2,070,076
Proved undeveloped	-	-	-	366,430	409,740	434,720	2,365,069	1,318,801	2,584,869
Total proved reserves	657,280	1,379,170	887,142	1,615,180	2,477,930	2,028,168	4,119,737	3,211,247	4,654,945

(1) Our reserve estimates as of December 31, 2016 and 2015 are based on reserve reports prepared by Jane E. Trusty, PE. Ms. Trusty is an independent petroleum engineer and a State of Texas Licensed Professional Engineer (License #60812). The reserve estimates provided by Ms. Trusty were based upon her review of the production histories and other geological, economic, ownership and engineering data, as provided by us or as obtained from the operators of our properties. A copy of Ms. Trusty's report is filed as an exhibit to this report on Form 10-K.

(2) Our reserve estimates as of December 31, 2014 were based on the reserve report prepared by Cawley, Gillespie & Associates, Inc., or CGA. CGA is a nationally recognized independent petroleum engineering firm and is a Texas Registered Engineering Firm (F-693). Our primary contact at CGA is Mr. W. Todd Brooker, Senior Vice President and a State of Texas Licensed Professional Engineer (License #83462). The reserve estimates were based upon the review by CGA of the production histories and other geological, economic, ownership and engineering data, as provided by us or as obtained from the operators of our properties. A copy of CGA's December 31, 2014 report was previously filed as an exhibit to our 2014 Annual Report on Form 10-K and is herein incorporated by reference as an exhibit to this report on Form 10-K.

As of December 31, 2016, our proved reserves totaled 887,142 BOE, of which approximately 100% were classified as proved developed. On a BOE basis, approximately 74% of the total is derived from 657,280 Bbls of oil and 26% is derived from 1,379,170 Mcf of natural gas. See the "Glossary of Oil and Gas Terms" for an explanation of these and other terms.

You should not place undue reliance on estimates of proved reserves. See " *Risk Factors - 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.* " A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetrics, material balance, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

We believe we maintain an effective system of internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information is assessed for validity when meetings are held with management, land personnel and third party operators to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Our reserve database is currently maintained by Jane Trusty, PE. Ms. Trusty works with our personnel to review field performance, future development plans, current revenues and expense information. Following these reviews, the reserve database and supporting data is updated so that Ms. Trusty can prepare her independent reserve estimates and final report.

Proved Undeveloped Reserves. As of December 31, 2016, we did not book any proved undeveloped reserves. During 2015 our proved undeveloped reserves were 434,720 BOE of proved undeveloped reserves as of December 31, 2015. This decrease was primarily due to a continued depression in global commodity prices in 2016.

As of December 31, 2016, we have no proved undeveloped reserves that have been included in this category for more than five years and we have recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well. As a result of the continued low oil price environment in 2016, we did not incur any capital expenditures to convert our proved undeveloped reserves to producing status and we do not intend to incur capital expenditures for this purpose in 2017.

Oil and Gas Production, Production Prices, and Production Costs. The following table sets forth certain information regarding our net production volumes, average sales prices realized and certain expenses associated with sales of oil and gas for the years ended December 31, 2016, 2015 and 2014.

	2016	2015	2014
Production Volume			
Oil (Bbls)	132,429	221,650	329,828
Natural gas (Mcfe)	477,351	553,505	813,081
BOE	211,988	313,901	465,342
Daily Average Production Volume			
Oil (Bbls per day)	363	607	904
Natural gas (Mcfe per day)	1,308	1,516	2,228
BOE per day	581	860	1,275
Net prices realized			
Oil per Bbl	$ 35.41	$ 40.82	$ 85.89
Natural gas per Mcfe	2.29	2.26	4.98
Oil and natural gas per BOE	27.11	32.80	69.58
Operating Expenses per BOE			
Production costs	$ 12.87	$ 23.42	$ 22.86
Depletion, depreciation and amortization	11.93	26.80	31.56

We encourage you to read this information in conjunction with the information contained in our financial statements and related notes included in Item 8 of this report on Form 10-K.

The following table provides a regional summary of our production for the years ended December 31, 2016, 2015 and 2014:

	2016			2015			2014		
	Oil (Bbl)	Gas (Mcfe)	Total (BOE)	Oil (Bbl)	Gas (Mcfe)	Total (BOE)	Oil (Bbl)	Gas (Mcfe)	Total (BOE)
Williston Basin (North Dakota)	103,423	149,944	128,774	163,380	151,191	188,579	212,052	198,375	245,115
Eagle Ford / Buda (South Texas)	25,192	136,441	47,932	53,149	232,094	91,831	110,413	437,130	183,268
Austin Chalk (South Texas)	3,634	1,347	3,858	4,860	4,190	5,558	6,627	5,191	7,492
Gulf Coast (Louisiana and Texas)	180	189,619	31,424	261	166,030	27,933	736	172,379	29,466
Total	132,428	477,351	211,988	221,650	553,505	313,901	329,828	813,075	465,341

Drilling and Other Exploratory and Development Activities. The following table sets forth information with respect to development and exploratory wells in which we own an interest in during the periods ended December 31, 2016, 2015 and 2014.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	0	0	13.0	0.5	14.0	1.6
Non-productive	-	-	-	-	-	-
Sub-total	0	0	13.0	0.5	14.0	1.6
Exploratory wells:						
Productive	0	0	1.0	0.3	21.0	2.7
Non-productive	-	-	-	-	-	-
Sub-total	0	0	1.0	0.3	21.0	2.7
Total	0	0	14.0	0.8	35.0	4.3

The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells. The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and gas that may ultimately be recovered. See Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations – General Overview* in this Annual Report on Form 10-K.

Oil and Gas Properties, Wells, Operations and Acreage. The following table summarizes information about our gross and net productive wells as of December 31, 2016.

	Gross Producing Wells			Net Producing Wells			Average Working Interest		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
North Dakota	114	-	114	11.08	-	11.08	9.7%	0.0%	9.7%
Texas	36	-	36	9.69	-	9.69	26.9%	0.0%	26.9%
Louisiana	-	1	1	-	0.17	0.17	17.0%	17.0%	17.0%
Total	150	1	151	20.77	0.17	20.94	13.9%	17.0%	13.9%

For purposes of the above table, a well with multiple completions in the same bore hole is considered one well. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion. As of December 31, 2016, none of the wells in the above table contain multiple completions.

Acreage. The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2016.

Area	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Williston Basin (North Dakota):						
Rough Rider Prospect	19,200	1,175	-	-	19,200	1,175
Yellowstone and SEHR Prospects	35,840	1,225	-	-	35,840	1,225
ASEN North Dakota Acquisition	16,320	114	-	-	16,320	114
East Texas and Louisiana:	1,824	289	-	-	1,824	289
Buda/Eagle Ford/Austin Chalk (Texas):						
Leona River Prospect	3,765	1,130	-	-	3,765	1,130
Booth Tortuga Prospect	12,013	3,050	-	-	12,013	3,050
Big Wells Prospect	240	36	4,003	600	4,243	636
Carrizo Creek and South McKnight Prospects	640	213	1,994	126	2,634	339
Total	89,842	7,232	5,997	726	95,839	7,958

As a non-operator, we are subject to lease expiration if the operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage will expire at the end of their respective primary terms unless we renew the existing leases, establish commercial production from the acreage or a “savings clause” is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have commenced. While we generally expect to test or establish production from most of our acreage prior to expiration of the applicable lease terms, there is no assurance that we can or will do so. As of December 31, 2016, all of our acreage in the Williston Basin and Louisiana is held by production. For our properties in Texas, the approximate expiration of our gross and net acres are set forth below:

Year Ending December 31,	Texas [(1)]	
	Gross	Net
2017	761	203
Total	761	203

(1) Includes acreage located in the Buda, Eagle Ford, and Austin Chalk areas of South Texas.

Present Activities. As of April 14, 2017 no wells were being drilled and no wells were pending completion on acreage in which we own working interests.

Real Estate

We own a 14-acre tract in Riverton, Wyoming with a two-story, 30,400 square foot office building. The first floor is rented to non-affiliates and government agencies; the second floor was formerly occupied by the Company. We are currently attempting to secure tenants for the vacant portion of this building but we are also considering an outright sale of the property.

In addition, we own three city lots covering 13.84 acres adjacent to our corporate office building in Fremont County, Wyoming. We intend to sell these properties without development. However, there can be no assurance that sales of any of these properties will be completed on the terms, or in the time frame, we expect or at all.

Uranium

Anfield Resources. In 2007, we sold all of our uranium assets for cash and stock of the purchaser, Uranium One Inc. ("Uranium One"). The assets sold included a uranium mill in Utah and unpatented uranium claims in Wyoming, Colorado, Arizona and Utah. Pursuant to the asset purchase agreement, we were entitled to additional consideration from Uranium One up to $40.0 million based on the performance of the mill, achievement of commercial production and royalties, but no additional consideration was ever received from Uranium One. In August 2014, we entered into an agreement with Anfield Resources Inc. ("Anfield") whereby if Anfield was successful in acquiring the property from Uranium One, we agreed to release Anfield from the future payment obligations stemming from our 2007 sale to Uranium One. On September 1, 2015, Anfield acquired the property from Uranium One and is now obligated to provide the following consideration to us:

- Issuance of $2.5 million in Anfield common shares to us. The Anfield shares are to be held in escrow and released in tranches over a 36-month period. Pursuant to the agreement, if any of the share issuances result in the Company holding in excess of 20% of the then issued and outstanding shares of Anfield (the "Threshold"), such shares in excess of the Threshold would not be issued at that time, but deferred to the next scheduled share issuance. If, upon the final scheduled share issuance the number of shares to be issued exceeds the Threshold, the value in excess of the Threshold is payable to us in cash,
- $2.5 million payable in cash upon 18 months of continuous commercial production, and
- $2.5 million payable in cash upon 36 months of continuous commercial production.

The first tranche of common shares resulted in the issuance of 7,436,505 shares of Anfield with a market value of $750,000 and such shares were delivered to us in September 2015. The second tranche of shares resulted in the issuance of 3,937,652 additional shares of Anfield with a market value of $750,000, and such shares were delivered to us in September 2016. Since the trading volume in Anfield shares has increased since we took possession, we determined a mark-to-market technique would be the most appropriate method to determine the fair value for Anfield shares. The primary factor in using a mark-to-market valuation in determining the fair value of Anfield shares is justified because of our belief that due to the increased liquidity in the stock, using current market prices for Anfield shares reflects the most accurate fair value calculation. At December 31, 2016, we determined the fair value of the Anfield shares to be approximately $0.9 million. The timing of any future receipt of cash from Anfield is not determinable and there can be no assurance that any cash will ever be received from Anfield or that the shares received from Anfield will ever be liquidated for cash.

Royalty on Uranium Claims. We hold a 4% net profits interest on certain unpatented mining claims on Rio Tinto's Jackpot uranium property located on Green Mountain in Wyoming. To date, we have not received any payments related to this royalty and there can be no assurance that any amount will ever be received.

Marketing, Major Customers and Delivery Commitments

Markets for oil and gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. All of our production is marketed by our industry partners for our benefit and is sold to competing buyers, including large oil refining companies and independent marketers. Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors. We had no material delivery commitments as of December 31, 2016.

Competition

The oil and gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and gas. Our competitors principally consist of major and intermediate sized integrated oil and gas companies, independent oil and gas companies and individual producers and operators. In particular, we compete for property acquisitions and our operating partners compete for the equipment and labor required to operate and develop our properties. Our competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Item 3 – Legal Proceedings

Material legal proceedings pending at December 31, 2016 and developments in those proceedings through April 14, 2017 are summarized below.

Statoil ASA

In June 2011, Brigham Oil & Gas, L.P. ("Brigham"), as the operator of the Williston 25-36 #1H Well, filed an action in the State of North Dakota, County of Williams, in District Court, Northwest Judicial District, Case No. 53-11-CV-00495 to interplead to the court with respect to the undistributed suspended royalty funds from this well to protect itself from potential litigation. Brigham became aware of an apparent dispute with respect to ownership of the mineral interest between the ordinary high water mark and the ordinary low water mark of the Missouri River. Brigham suspended payment of certain royalty proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Brigham was subsequently sold to Statoil ASA ("Statoil") who assumed Brigham's rights and obligations under this case. The Company owns a working interest, not royalty interest, in this well and no funds have been withheld.

On January 28, 2013, the District Court Northwest Judicial District issued an Order for Partial Summary Judgment holding that the State of North Dakota as part of its title to the beds of navigable waterways owns the minerals in the area between the ordinary high and low watermarks on these waterways, and that this public title excludes ownership and any proprietary interest by riparian landowners. This issue has been appealed to the North Dakota Supreme Court. Our legal position is aligned with Statoil, who will continue to provide legal counsel in this case for the benefit of all working interest owners.

Reformed Assignments

We are also a party to litigation that seeks to reform certain assignments of mineral interests we acquired from Brigham. This matter involves the depth below the surface to which the assignments were effective. The plaintiff is seeking to reform the agreement such that our assignment would be revised to be 12 feet closer to the surface. This dispute affects one of our producing wells.

Quiet Title Action – Willerson Lease

In September 2013, we acquired from Chesapeake Exploration, LLC ("Chesapeake") a 15% working interest in approximately 4,244 gross mineral acres in Dimmit County, Texas, that are leased from Dr. Darrell Willerson and affiliates ("Willerson"). In January 2014, Willerson inquired if their lease had terminated due to the failure to achieve production in paying quantities pursuant to the terms of the lease. Along with Crimson Exploration Operating, Inc. and Liberty Energy, LLC, we filed a declaratory judgment action in the District Court of Dimmit County in May 2014 seeking a determination from the court that the lease remains valid and in effect. Willerson counterclaimed for breach of contract, trespass, and related causes of action. In January 2016, Willerson filed a third-party petition alleging breach of contract, trespass, and related causes of action against Chesapeake and EXCO Operating Company, LP. The matter has settled with The Company's portion being $75,000 plus the related legal fees. Legal fees are still being determined.

Arbitration of Employment Claim

A former employee has claimed that we owe up to $1.8 million under an Executive Severance and Non-Compete Agreement (the "Agreement") due to a change of control and termination of employment without cause. The Agreement requires that any disputes be submitted to binding arbitration and a request for arbitration was submitted by the former employee in March 2016. We do not believe there is any merit to the claims of termination without cause or that a change of control occurred. Arbitration proceedings are expected to commence in 2017.

Item 4 – Mine Safety Disclosures

Not applicable.

PART II

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

Market Information

Our common stock is traded on the over-the-counter market, and prices are reported on a "last sale" basis on the Nasdaq Capital Market. The following quarterly high and low closing sale prices reflects the Company's 6 for 1 reverse common stock split which took effect June 22, 2016:

	Low	High
Year ended December 31, 2016:		
First quarter	$ 0.87	$ 2.70
Second quarter	1.70	2.40
Third quarter	1.68	2.49
Fourth quarter	1.28	2.29
Year ended December 31, 2015:		
First quarter	$ 6.78	$ 9.96
Second quarter	3.17	8.22
Third quarter	2.16	4.28
Fourth quarter	0.72	3.03

As of April 14, 2017, the closing sales price was $0.91 per share.

In order for us to maintain the listing of our shares of common stock on the NASDAQ Capital Market®, the common stock must maintain a minimum bid price of $1.00 as set forth in NASDAQ Marketplace Rule 5550(a)(2). If the closing bid price of the common stock is below $1.00 for 30 consecutive trading days, then the closing bid price of the common stock must be $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the rule. We cannot guarantee that we will be able to remain in compliance with the minimum price requirement within the grace period or satisfy other continued listing requirements. If our common stock is delisted from trading on the NASDAQ Capital Market, it may be eligible for trading over the counter, but the delisting of our common stock from NASDAQ could adversely impact the liquidity and value of our common stock. On March 27, 2017, we were given notice by the NASDAQ Capital Market that the closing price of our common stock has traded below $1.00 for 30 consecutive days. We have 180 calendar days to return to compliance.

Holders

As of April 14, 2017, there were approximately 808 shareholders of record, and we had 6,134,506 shares of common stock issued and outstanding.

Dividends

We did not declare or pay any cash dividends on common stock during fiscal years 2016 and 2015 and do not intend to declare any cash dividends in the foreseeable future. Our ability to pay dividends in the future is subject to limitations under state law and the terms of the Credit Facility, which restricts the ability of Energy One to pay dividends to the Company. Our ability to pay dividends on our common stock is also limited by the terms of our Series A Convertible Preferred Stock issued in February 2015. See Note 7 to the Consolidated Financial Statements herein and *Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments.*

Issuance of Securities in 2016

During 2016, we issued a total of 351,000 shares of common stock to six directors of the Company pursuant to restricted stock grants under our 2012 Equity and Performance Incentive Plan.

On December 21, 2016, the Company completed a registered direct offering of 1,000,000 shares of common stock at a net price of $1.50 per share for total net proceeds of approximately $1.37 million. Additionally, the investors received warrants to purchase 1,000,000 shares of Common stock from the Company at an exercise price of $2.05 per share, subject to adjustment, for a period of five years from closing.

Item 6. Selected Financial Data

The following table sets forth selected supplemental financial and operating data as of the dates and periods indicated. The financial data for each of the five years presented were derived from our consolidated financial statements. The following data should be read in conjunction with *Management's Discussion and Analysis of Financial Condition and Results of Operations* in Item 7 of this report, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our consolidated financial statements included in this report.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(Dollars in Thousands, Except Per Share Amounts)				
Revenue from oil and gas sales	$ 5,746	$ 10,296	$ 32,379	$ 33,647	$ 32,534
Operating expenses:					
Oil and gas production costs	2,728	7,352	10,638	10,469	10,788
Depreciation, depletion and amortization	2,529	8,412	14,685	13,623	14,893
Impairment of oil and gas properties	9,568	57,676	-	5,828	5,189
General and administrative:					
Stock-based compensation	213	948	527	384	345
Other	2,637	4,972	5,909	5,018	8,764
Total operating expenses	17,675	79,360	31,759	35,322	39,979
Operating Income/(loss)	(11,929)	(69,064)	620	(1,675)	(7,445)
Non-operating income (expense):					
Gain (loss) on oil price risk derivatives	(194)	1,559	582	(1,075)	1,091
Other income (expense), net	893	484	200	(1,336)	(39)
Interest expense	(442)	(263)	(385)	(429)	(203)
Income/(loss) before income taxes and discontinued operations	(11,672)	(67,284)	1,017	(4,515)	(6,596)
Income tax benefit	-	-	-	-	44
Loss from continuing operations	(11,672)	(67,284)	1,017	(4,515)	(6,552)
Discontinued operations:					
Discontinued operations	(2,448)	(2,992)	(3,108)	(2,744)	(2,802)
Impairment loss	-	(22,620)	-	(120)	(1,891)
Loss from discontinued operations	(2,448)	(25,612)	(3,108)	(2,864)	(4,693)
Net loss	$ (14,120)	$ (92,896)	$ (2,091)	$ (7,379)	$ (11,245)
Earnings/(loss) per share- basic					
Continuing operations	$ (2.45)	$ (14.38)	$ 0.04	$ (0.98)	$ (1.43)
Discontinued operations	(0.51)	(5.48)	(0.12)	(0.62)	(1.03)
Total	$ (2.96)	$ (19.86)	$ (0.08)	$ (1.60)	$ (2.46)
Loss per share- diluted					
Continuing operations	$ (2.45)	$ (14.38)	$ 0.04	$ (0.98)	$ (1.43)
Discontinued operations	(0.51)	(5.48)	(0.12)	(0.62)	(1.03)
Total	$ (2.96)	$ (19.86)	$ (0.08)	$ (1.60)	$ (2.46)
Weighted average shares outstanding					
Basic	4,768,013	4,677,500	4,638,833	4,612,667	4,577,833
Diluted	4,768,013	4,677,500	4,638,833	4,612,667	4,577,833

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(Dollars in Thousands, Except Financial Results Per BOE Amounts)				
Oil and gas production quantity (BOE)	211,988	313,901	465,342	424,933	444,702
Financial results per BOE:					
Realized oil and gas sales price	$ 27.11	$ 32.80	$ 69.58	$ 79.18	$ 73.16
Oil and gas production costs	(12.87)	(23.42)	(22.86)	(24.64)	(24.26)
Depletion, depreciation and amortization	(11.93)	(26.80)	(31.56)	(32.06)	(33.49)
General and administrative expense	(13.44)	(18.86)	(13.83)	(12.71)	(20.48)
Cash flow data					
Net cash provided by (used in):					
Operating activities	$ (1,405)	$ 2,504	$ 23,737	$ 20,143	$ 16,038
Investing activities	(193)	(565)	(19,542)	(18,219)	(20,877)
Financing activities	1,211	(154)	(3,055)	(10,821)	(2,433)
Discontinued operations	(448)	(2,441)	(2,985)	11,927	(2,777)
Balance sheet and reserve data (at end of year)					
Working capital (deficit)	$ (6,043)	$ (9,778)	$ (654)	$ 5,970	$ 12,762
Oil and gas properties, using full cost method	9,858	23,432	88,269	86,922	85,634
Total assets	16,767	33,132	123,523	126,801	140,827
Long-term debt, less current portion	-	-	6,000	9,000	10,000
Total shareholders' equity	3,758	15,475	107,395	109,057	116,117
Reserve data (at end of year)					
Total proved oil and gas reserves (BOE)	887,142	2,028,168	4,654,944	3,855,031	2,913,324
Proved developed oil and gas reserves (BOE)	887,142	1,593,448	2,070,076	2,159,075	2,007,375

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

This discussion includes forward-looking statements. Please refer to *Cautionary Statement Regarding Forward-Looking Statements* of this report on Form 10-K for important information about these types of statements. Additionally, please refer to the *Glossary of Oil and Gas Terms* of this report on Form 10-K for oil and gas industry terminology used herein.

General Overview

We are an independent energy company focused on the lease acquisition and development of oil and gas producing properties in the continental United States. Our business is 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 currently explore for and produce oil and gas through a non-operator business model; however, we may operate oil and gas properties for our own account and may expand our holdings or operations into other areas. As a non-operator, we rely on our operating partners to propose, permit and manage wells. Before a well is drilled, the operator is required to provide all oil and gas interest owners in the designated well the opportunity to participate in the drilling costs and revenues of the well on a pro-rata basis. After the well is completed, our operating partners also transport, market and account for all production. As discussed in Item 1. Business, our long-term strategic focus is to develop operational capabilities through the pursuit of opportunities to acquire operated properties and/or operatorship of existing properties.

Recent Developments

On February 24, 2017, the Company received confirmation from IronHorse Resources, LLC ("Ironhorse") of the termination of a previously announced agreement dated January 3, 2017.

The Company's quarterly reserve reports are prepared based on a trailing 12-month average for benchmark oil and gas prices. The weighted average oil price used to prepare reserve estimates and to calculate the Full Cost Ceiling limitation for the year end of 2016 has increased. Assuming other variables remain substantially unchanged, the Company does not expect to record an impairment charge during the first quarter of 2017.

As of December 31, 2016, the Company was not in compliance with any of the financial covenants under its credit facility and on March 31, 2017, the lender did not provide a limited waiver for the Company's noncompliance.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the United States ("GAAP") requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates under different assumptions or conditions. A summary of our significant accounting policies is detailed in *Note 1 – Organization, Operations and Significant Accounting Policies* in Item 8 of this report on Form 10-K. We have outlined below those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Oil and Gas Reserve Estimates. Our estimates of proved reserves are based on quantities of oil and gas reserves which current engineering data indicates are recoverable from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are critical estimates in determining our depreciation, depletion and amortization expense ("DD&A") and our full cost ceiling limitation ("Full Cost Ceiling"). Future cash inflows are determined by applying oil and gas prices, as adjusted for transportation, quality and basis differentials to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Future production and development costs are based on costs existing at the effective date of the report. Expected cash flows are discounted to present value using a prescribed discount rate of 10% per annum.

Estimates of proved reserves are inherently imprecise because of uncertainties in projecting rates of production and timing of developmental expenditures, interpretations of geological, geophysical, engineering and production data and the quality and quantity of available data. Changing economic conditions also may affect our estimates of proved reserves due to changes in developmental costs and changes in commodity prices that may impact reservoir economics. We utilize independent reserve engineers to estimate our proved reserves at the end of each fiscal quarter during the year.

Oil and Gas Properties. We follow the full cost method in accounting for our oil and gas properties. 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 property 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 are amortized using the equivalent unit-of-production method, based on proved oil and gas reserves. The capitalized costs are amortized over the life of the reserves associated with the assets, with the DD&A recognized in the period that the reserves are produced. DD&A is calculated by dividing the period's production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the sum of the capitalized investment and estimated future development costs associated with the investment. Changes in our reserve estimates will therefore result in changes in our DD&A per unit. Costs associated with production and general corporate activities are expensed in the period incurred.

Exploratory wells in progress are excluded from the DD&A calculation until the outcome of the well is determined. Similarly, unproved property costs are initially excluded from the DD&A calculation. Unproved property costs not subject to the DD&A calculation consist primarily of leasehold and seismic costs related to unproved areas. Unproved property costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved oil and gas properties are assessed quarterly for impairment to determine whether we are still actively pursuing the project and whether the project has been proven either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated DD&A and net of deferred income taxes may not exceed the Full Cost Ceiling. The Full Cost Ceiling is equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the unimpaired cost of unproved properties not subject to amortization, plus the lower of cost or fair value of unproved properties that are subject to amortization. When net capitalized costs exceed the Full Cost Ceiling, impairment is recognized.

Derivative Instruments. We use derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk underlying our oil and gas production. We may also use puts, calls and basis swaps in the future. All derivative instruments are recorded in the consolidated balance sheets at fair value. We offset fair value amounts recognized for derivative instruments executed with the same counterparty. Although we do not designate any of our derivative instruments as cash flow hedges, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on oil price risk derivatives in our consolidated statements of operations.

Our Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties. The master contracts with approved counterparties identify the CEO as the Company representative authorized to execute trades.

Discontinued Operations- Mining Properties. Due to the disposition of our mining properties in February 2016, all of our mining properties are included in discontinued operations. Effective January 1, 2015, we adopted new accounting guidance related to the recognition and presentation of discontinued operations in our financial statements. Under the revised guidance, beginning in 2015 only disposals of businesses that represent strategic shifts that have a major effect on our operations and financial results are reported in discontinued operations. Accordingly, the disposal of our mining segment qualified for reporting as discontinued operations.

We capitalized all costs incidental to the acquisition of mining properties and related equipment. The costs of operating a related water treatment plant on the mine property, holding costs to maintain permits, mining exploration costs and general corporate overhead were expensed as incurred.

Joint Interest Operations. We do not serve as operator for any of our oil and gas properties. Therefore, we rely to a large extent on the operator of the property to provide us with timely and accurate information about the operations of the properties. Joint interest billings from the operators serve as our primary source of information to record revenue, operating expenses and capital expenditures for our properties on a monthly basis. Many of our properties are subject to complex participation and operating agreements where our working interests and net revenue interests are subject to change upon the occurrence of certain events, such as the achievement of "payout." These calculations may be subject to error and differences of interpretation which can cause uncertainties about the proper amount that should be recorded in our accounting records. When these issues arise, we make every effort to work with the operators to resolve the issues promptly.

Revenue Recognition. We record oil and gas revenue under the sales method of accounting. Under the sales method, we recognize revenues based on the amount of oil or natural gas sold to purchasers, which may differ from the amounts to which we are entitled based on our interest in the properties. Gas balancing obligations as of December 31, 2016 and 2015 were not significant.

Stock Based Compensation. We measure the cost of employee services received in exchange for all equity awards granted, including stock options, based on the fair market value of the award as of the grant date. We recognize the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. For awards granted which contain a graded vesting schedule, and the only condition for vesting is a service condition, compensation cost is recognized as an expense on a straight-line basis over the requisite service period as if the award was, in substance, a single award.

Recently Issued Accounting Standards

Please refer to the section entitled *Recent Accounting Pronouncements* under *Note 1 – Organization, Operations and Significant Accounting Policies* in Item 8 of this report on Form 10-K for additional information on recently issued accounting standards and our plans for adoption of those standards.

Results of Operations

Comparison of our Statements of Operations for the Years Ended December 31, 2016 and 2015

During the year ended December 31, 2016, we recorded a net loss of $14.1 million as compared to a net loss of $92.9 million for the year ended December 31, 2015. Our loss from continuing operations was $11.9 million for the year ended December 31, 2016 compared to a loss from continuing operations of $67.3 million for the year ended December 31, 2015. In the following sections we discuss our revenue, operating expenses, non-operating income, and discontinued operations for the year ended December 31, 2016 compared to the year ended December 31, 2015.

Revenue. Presented below is a comparison of our oil and gas sales, production quantities and average sales prices for the years ended December 31, 2016 and 2015 (dollars in thousands, except average sales prices):

			Change	
	2016	2015	Amount	Percent
Revenue:				
Oil	$ 4,689	$ 9,047	$ (4,358)	-48%
Gas	1,057	1,249	(192)	-15%
Total	$ 5,746	10,296	$ (4,550)	-44%
Production quantities:				
Oil (Bbls)	132,429	221,650	(89,221)	-40%
Gas (Mcfe)	447,351	553,505	(106,154)	-19%
BOE	211,988	313,901	(101,913)	-34%
Average sales prices:				
Oil (Bbls)	$ 35.41	$ 40.82	$ (3.37)	-8%
Gas (Mcfe)	2.29	2.26	0.03	1%
BOE	27.11	32.80	(5.69)	-17%

The decrease in our oil sales of $4.4 million for the year ended December 31, 2016 resulted from a 40% reduction in our oil production and an 8% reduction in the average oil price realized during 2016 compared to 2015. The decrease in our gas sales of $0.2 million for the year ended December 31, 2016, was driven by a 19% decrease in our gas production during 2016 compared to 2015. The reduction in our net realized oil and gas prices is reflective of the continued global commodity price depression. During 2016, the differential between West Texas Intermediate ("WTI") quoted prices for crude oil and the prices we realize for sales in the Williston Basin was approximately $6.00 per barrel lower. We expect this differential to continue (with the amount of the differential varying over time) and that our oil sales revenue will be affected by lower realized prices from this region.

For the year ended December 31, 2016, we produced 211,988 BOE, or an average of 581 BOE per day, as compared to 313,901 BOE or 860 BOE per day in 2015. Production for our Williston Basin properties decreased by 59,806 BOE during 2016, which is a 32% reduction compared to 2015. This decrease of 32% is consistent with the decrease in Williston Basin production as a result of normal production declines combined with lower working interests for wells that have achieved payout. Production for our Eagle Ford and Buda properties in South Texas decreased by 43,899 BOE during 2016, which is a 48% reduction compared to 2015. This reduction was attributable to the normal decline in production for wells in this area and we did not participate in further drilling in this area during 2016.

Oil and Gas Production Costs. Presented below is a comparison of our oil and gas production costs for the years ended December 31, 2016 and 2015 (dollars in thousands):

			Change	
	2016	**2015**	**Amount**	**Percent**
Production taxes and other expenses	$ 790	$ 1,021	$ (231)	-22%
Lease operating expense	1,938	6,331	(4,393)	-69%
Total	$ 2,728	$ 7,352	$ (4,623)	-63%

For the year ended December 31, 2016, production taxes decreased by $0.2 million compared to 2015. The decrease in production taxes is primarily a result of lower oil and gas sales. For the year ended December 31, 2016, lease operating expense decreased by $4.4 million which was primarily due to the implementation of cost reduction strategies by the operators of our wells, combined with a downward revision to our payable to major operator liability due to revised ownership interests in the associated properties.

Depreciation, depletion and amortization. Our DD&A rate for the year ended December 31, 2016 was $11.93 per BOE compared to $26.80 per BOE for 2015. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves. The primary factors that resulted in a reduction in our DD&A rate for the year ended December 31, 2016 were quarterly impairment charges that resulted from our quarterly Full Cost Ceiling limitations and a write down of our Proved Undeveloped reserves.

Impairment of oil and gas properties. During the years ended December 31, 2016 and 2015, we recorded impairment charges related to our oil and gas properties of $9.6 million and $57.7 million, respectively, because the net capitalized costs were in excess of the Full Cost Ceiling limitation. These quarterly impairment charges were primarily due to the deepening declines in global commodity prices. Presented below are the weighted average prices (before applying the impact of basis differentials between the benchmark prices and the actual prices realized for our wells) used to prepare our reserve estimates and to calculate our Full Cost Ceiling limitations for each of the four quarters in 2016, along with the impairment charges recognized during each of the four quarters in 2016 (dollars in thousands, except average prices):

	Average Price		
	Oil (Bbl)	**Gas (MMbtu)**	**Impairment Charge**
First quarter	$ 46.26	$ 2.40	$ 6,957
Second quarter	43.12	2.24	2,611
Third quarter	41.68	2.28	-
Fourth quarter	42.75	2.48	-
Total impairment			$ 9,568

Our quarterly reserve reports are prepared based on a trailing 12-month average for benchmark oil and gas prices. The weighted average oil price used to prepare reserve estimates and to calculate the Full Cost Ceiling limitation for the first quarter of 2017 is expected to increase from $42.75 to approximately $44.00 (both before further deductions for basis differentials). Assuming other variables remain substantially unchanged, we do not expect to record an impairment charge during the first quarter of 2017.

General and Administrative Expenses. Presented below is a comparison of our general and administrative expenses for the years ended December 31, 2016 and 2015 (dollars in thousands):

	2016	2015	Change Amount	Change Percent
Compensation and benefits, including directors	$ 640	$ 2,602	$ (1,962)	-75%
Stock-based compensation	213	948	(735)	-78%
Employee severance costs	3	504	(501)	-100%
Professional fees, insurance and other	1,994	1,866	128	7%
Total	$ 2,850	$ 5,920	$ (3,070)	-52%

General and administrative expenses decreased by $3.1 million for the year ended December 31, 2016 compared to the year ended December 31, 2015. This decrease was primarily attributable to a reduction of $1.9 million, $0.7 million, and $0.5 million in compensation and benefits, stock based compensation, and employee severance costs, respectively. The reductions are attributable to a reduction in employees and overhead.

Non-Operating Income (Expense). Presented below is a comparison of our non-operating income (expense) for the years ended December 31, 2016 and 2015 (dollars in thousands):

	2016	2015	Change Amount	Change Percent
Realized gain (loss) on oil price risk derivatives	$ 1,440	$ (75)	$ 1,515	N/A
Unrealized gain (loss) on oil price risk derivatives	(1,634)	1,634	(3,268)	N/A
Gain on sale of assets	102	121	(19)	-16%
Gain (loss) on investments	750	(68)	818	N/A
Rental and other income (loss)	(169)	431	(600)	N/A
Gain on Warrant Revaluation	210	-	210	N/A
Interest expense	(442)	(263)	(179)	-68%
Total	$ 257	$ 1,780	$ (1,523)	-86%

We recognized a realized gain on oil price risk derivatives of $1.4 million for the year ended December 31, 2016 compared to a loss of $0.1 million for 2015. We recognized an unrealized loss on oil price risk derivatives of $1.6 million for the year ended December 31, 2016 compared to a gain of $1.6 million for 2015. The realized and unrealized loss for 2016 was $0.2 million compared to a realized and unrealized gain of $1.6 million for 2015.

During each of the years ended December 31, 2016 and 2015, we recorded a gain on the sale of assets of $0.1 million, which resulted from the sale of non-oil and gas related property and equipment. During the year ended December 31, 2016, we recorded a gain on investment of $0.8 million from the receipt of shares related to the disposition of a portion of our mining assets. During the year ended December 31, 2016, we determined that our marketable equity securities had experienced an impairment in value which resulted in an unrealized loss of $0.2 million. During the year ended December 31, 2016, we realized a gain on the revaluation of our outstanding warrants of $0.2 million. Our warrant liability is accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. No warrants were outstanding for the year ending December 31, 2015. We will continue to revalue our outstanding warrants on a quarterly basis.

Interest expense increased by $0.2 million during the year ended December 31, 2016 compared to 2015. This increase was primarily attributable to an increase in our weighted average borrowing for 2016.

Discontinued Operations. Due to the disposition of our mining properties in February 2016, all of our mining properties are included in discontinued operations for all periods presented in this report. At year end December 31, 2016 we recognized no impairment charge and December 31, 2015, we recognized an impairment charge of $22.6 million, respectively, when we determined that the carrying value could not be recovered. During the years ended December 31, 2016 and 2015, the costs of operating our water treatment plant on the mine property, holding costs to maintain permits, and general corporate overhead associated with the mine property were expensed as incurred. The total operating and holding expenses amounted to $2.1 million for the year ended December 31, 2016 compared to $3.0 million for 2015. The total operating and holding expense amount of $2.1 million for the year ended December 31, 2016 includes the value of the preferred stock issued as part of the transaction considerations.

Comparison of our Statements of Operations for the Years Ended December 31, 2015 and 2014

During the year ended December 31, 2015, we recorded a net loss of $92.9 million as compared to a net loss of $2.1 million for the year ended December 31, 2014. Our loss from continuing operations was $67.3 million for the year ended December 31, 2015 compared to a loss from continuing operations of $1.0 million for the year ended December 31, 2014. In the following sections we discuss our revenue, operating expenses, non-operating income, and discontinued operations for the year ended December 31, 2015 compared to the year ended December 31, 2014.

Revenue. Presented below is a comparison of our oil and gas sales, production quantities and average sales prices for the years ended December 31, 2015 and 2014 (dollars in thousands, except average sales prices):

			Change	
	2015	2014	Amount	Percent
Revenue:				
Oil	$ 9,047	$ 28,331	$ (19,284)	-68%
Gas	1,249	4,048	(2,799)	-69%
Total	$ 10,296	$ 32,379	$ (22,083)	-68%
Production quantities:				
Oil (Bbls)	221,650	329,828	(108,178)	-33%
Gas (Mcfe)	553,505	813,081	(259,576)	-32%
BOE	313,901	465,342	(151,441)	-33%
Average sales prices:				
Oil (Bbls)	$ 40.82	$ 85.89	$ (45.07)	-52%
Gas (Mcfe)	2.26	4.98	(2.72)	-55%
BOE	32.80	69.58	(36.78)	-53%

The decrease in our oil sales of $19.3 million for the year ended December 31, 2015, was driven by a 33% decrease in our oil production and a 52% reduction in average oil price realized. The decrease in our gas sales of $2.8 million for the year ended December 31, 2015 resulted from a 32% reduction in our gas production and a 55% reduction in the average gas price realized during 2015 compared to 2014. The differential between Nymex quoted prices for crude oil and the prices we realized for sales in the Williston Basin ranged from $11.00 to $6.00 per barrel during 2015. For the year ended December 31, 2015, we produced 313,901 BOE, or an average of 860 BOE per day, as compared to 465,342 BOE or 1,275 BOE per day in 2014. Production for our Eagle Ford and Buda properties in South Texas decreased by 91,437 BOE during 2015, which is a 50% reduction compared to 2014. These reductions were attributable to the normal decline in production for wells in this area and we did not participate in further drilling in this area during 2015 as a result of normal production declines and lower working interests in wells drilled in this region.

Oil and Gas Production Costs. Presented below is a comparison of our oil and gas production costs for the years ended December 31, 2015 and 2014 (dollars in thousands):

			Change	
	2015	2014	Amount	Percent
Production taxes and other expenses	$ 1,021	$ 2,758	$ (1,737)	-63%
Lease operating expense	6,331	7,880	(1,549)	-20%
Total	$ 7,352	$ 10,638	$ (3,286)	-31%

For the year ended December 31, 2015, production taxes decreased by $1.7 million as a result of the reduction in oil and gas sales. For the year ended December 31, 2015, lease operating expense decreased by $1.5 million due to a decrease in the number of producing wells per month.

Depreciation, depletion and amortization. Our DD&A rate for the year ended December 31, 2015 was $26.80 per BOE compared to $31.56 per BOE for 2014. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Impairment of oil and gas properties. During the year ended December 31, 2014, the Company did not recognize any oil and gas impairment expense. During the year ended December 31, 2015, we recorded impairment charges related to our oil and gas properties of $57.7 million because the net capitalized costs were in excess of the Full Cost Ceiling limitation. These quarterly impairment charges were primarily due to the deepening declines in the price of oil during 2015. Presented below are the weighted average prices (before applying the impact of basis differentials between the benchmark prices and the actual prices realized for our wells) used to prepare our reserve estimates and to calculate our Full Cost Ceiling limitations for each of the four quarters in 2015, along with the impairment charges recognized during each of the four quarters in 2015 (dollars in thousands, except average prices):

	Average Price		
	Oil (Bbl)	**Gas (MMbtu)**	**Impairment Charge**
First quarter	$ 82.72	$ 3.88	$ 19,240
Second quarter	71.68	3.39	3,208
Third quarter	59.21	3.06	21,446
Fourth quarter	50.28	2.59	13,782
Total impairment			$ 57,676

General and Administrative Expenses. Presented below is a comparison of our general and administrative expenses for the years ended December 31, 2015 and 2014 (dollars in thousands):

			Change	
	2015	**2014**	**Amount**	**Percent**
Compensation and benefits, including directors	$ 2,602	$ 4,124	$ (1,522)	-37%
Stock-based compensation	948	527	421	80%
Employee severance costs	504	-	504	N/A
Professional fees, insurance and other	1,866	1,785	81	5%
Total	$ 5,920	$ 6,436	$ (516)	-8%

General and administrative expenses decreased by $0.5 million for the year ended December 31, 2015 compared to the year ended December 31, 2014. This decrease was attributable to a reduction of $1.5 million in compensation and benefits, which was driven by (i) a decrease in executive retirement expense of $0.6 million since the actuarial calculations indicated the retirement plan was fully funded in 2015, (ii) a decrease in compensation and benefits of $0.6 million related to the retirement of two executive officers for all or part of 2015, (iii) a decrease in employee bonuses of $0.2 million, and (iv) a decrease in board of directors' compensation of $0.1 million. Other significant changes in general and administrative expenses included (i) an increase in stock-based compensation which primarily resulted from the acceleration of vesting of stock options and restricted stock associated with employees who terminated employment in 2015, and (ii) an increase in severance expense of $0.5 million which was comprised of $0.4 million for 3 executive officers and $0.1 million for 6 other employees who terminated employment by the end of 2015.

Non-Operating Income (Expense). Presented below is a comparison of our non-operating income (expense) for the years ended December 31, 2015 and 2014 (dollars in thousands):

			Change	
	2015	**2014**	**Amount**	**Percent**
Realized gain (loss) on oil price risk derivatives	$ (75)	$ 316	$ (391)	-124%
Unrealized gain (loss) on oil price risk derivatives	1,634	266	1,368	514%
Gain on sale of assets	121	112	9	8%
Loss on investments	(68)	-	(68)	N/A
Rental and other income	431	88	343	390%
Interest expense	(263)	(385)	122	-32%
Total	$ 1,780	$ 397	$ 1,383	348%

We recognized a realized loss on oil price risk derivatives of $0.1 million for the year ended December 31, 2015 compared to a gain of $0.3 million for 2014. We recognized an unrealized gain on oil price risk derivatives of $1.6 million for the year ended December 31, 2015 compared to a gain of $0.3 million for 2014. The realized and unrealized gain for 2015 was $1.6 million compared to a realized gain of $0.6 million for 2014, an improvement of $1.1 million which is indicative of the decline in the market for crude oil after we entered into the derivative contracts.

During each of the years ended December 31, 2015 and 2014, we recorded a gain on the sale of assets of $0.1 million, which resulted from the sale of non-oil and gas related property and equipment. During the year ended December 31, 2015, we determined that our marketable equity securities had experienced an other than temporary impairment in value which resulted in an unrealized loss of $0.1 million.

Interest expense decreased by $0.1 million during the year ended December 31, 2015 compared to 2014. This decrease was primarily attributable to a reduction in our weighted average borrowing for 2015.

Discontinued Operations. Due to the disposition of our mining properties in February 2016, all of our mining properties are included in discontinued operations for all periods presented in this report. As of December 31, 2015, we recognized an impairment charge of $22.6 million when we determined that the carrying value could not be recovered. During the years ended December 31, 2015 and 2014, the costs of operating our water treatment plant on the mine property, holding costs to maintain permits, and general corporate overhead associated with the mine property were expensed as incurred. The total operating and holding expenses amounted to $3.0 million for the year ended December 31, 2015 compared to $3.1 million for 2014.

Non-GAAP Financial Measures- Adjusted EBITDAX

Adjusted EBITDAX represents income (loss) from continuing operations as further modified to eliminate impairments, depreciation, depletion and amortization, stock-based compensation expense, loss on investments and non-operating income or expense, income taxes, unrealized derivative gains and losses, interest expense, exploration expense, and other items set forth in the table below. Adjusted EBITDAX excludes certain items that we believe affect the comparability of operating results and can exclude items that are generally one-time in nature or whose timing and/or amount cannot be reasonably estimated, such as the employee severance charges incurred in 2016.

Adjusted EBITDAX is a non-GAAP measure that is presented because we believe it provides useful additional information to investors and analysts as a performance measure. In addition, adjusted EBITDAX is widely used by professional research analysts and others in the valuation, comparison, and investment recommendations of companies in the oil and gas exploration and production industry, and many investors use the published research of industry research analysts in making investment decisions. Adjusted EBITDAX should not be considered in isolation or as a substitute for net income (loss), income (loss) from operations, net cash provided by operating activities, or profitability or liquidity measures prepared under GAAP. Because adjusted EBITDAX excludes some, but not all items that affect net income (loss) and may vary among companies, the adjusted EBITDAX amounts presented may not be comparable to similar metrics of other companies. Our wholly-owned subsidiary, Energy One LLC, is also subject to a debt to adjusted EBITDAX ratio as one of the financial covenants under its Credit Facility and the calculation for purposes of the Credit Facility differs from our financial reporting definition.

The following table provides reconciliations of income (loss) from continuing operations to adjusted EBITDAX for the years ended December 31, 2016, 2015 and 2014, in thousands:

	2016	2015	2014
Loss from continuing operations (GAAP)	$ (11,672)	$ (67,284)	$ (1,017)
Impairment of oil and gas properties	9,568	57,676	-
Depreciation, depletion and amortization	2,529	8,412	14,685
Gain/loss on investments	(750)	68	-
Stock-based compensation	213	948	527
Employee severance costs	3	504	-
Gain on sale of assets	(102)	(121)	(112)
Gain on warrant revaluation	(210)	-	-
Interest expense	442	263	385
Adjusted EBITDAX (Non-GAAP)	$ 21	$ 466	$ 16,502

Liquidity and Capital Resources

The following table sets forth certain measures about our liquidity as of December 31, 2016 and 2015, in thousands:

	2016	2015	Change
Cash and equivalents	$ 2,518	$ 3,354	$ (836)
Working capital deficit (1)	(6,043)	(9,778)	3,736
Oil and gas standardized measure (2)	6,747	17,768	(11,021)
Total assets	16,767	33,132	(16,365)
Outstanding debt under Credit Facility	6,000	6,000	-
Borrowing base under Credit Facility	6,000	6,000	-
Total shareholders' equity	3,758	15,475	(11,717)
Select Ratios			
Current ratio (3)	0.45 to 1.00	0.41 to 1.00	
Debt to equity ratio (4)	1.59 to 1.00	0.39 to 1.00	

(1) Working capital deficit is computed by subtracting total current liabilities from total current assets.

(2) The standardized measure is widely used in the oil and gas industry and is considered by lenders, institutional investors and professional analysts when comparing companies. See Note 16 to the consolidated financial statements included in Item 8 of this report on Form 10-K for further information about the standardized measure and changes therein.

(3) The current ratio is computed by dividing total current assets by total current liabilities.

(4) The debt to equity ratio is computed by dividing total debt by total shareholders’ equity.

As of December 31, 2016, we have a working capital deficit of $6.0 million compared to a working capital deficit of $9.8 million as of December 31, 2015, an improvement of $3.7 million. This improvement was primarily attributable to (i) the reclassification of historically disputed property ownership interests and (ii) an improvement in commodity prices in the 4 th quarter of 2016.

Our sole source of debt financing is a revolving Credit Facility with Wells Fargo Bank N.A. With lower oil and gas prices during 2015, Wells Fargo decreased the borrowing base by $18.5 million to $6.0 million which is the borrowing base in effect as of December 31, 2016. Outstanding borrowings as of December 31, 2016 were $6.0 million, and the Company did not have any borrowing availability as of December 31, 2016. Accordingly, this debt is classified as a current liability as of December 31, 2016.

During 2015 and 2016, we did not 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 provides 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 constitutes an event of default under the Credit Facility. Additionally, management expects that further non-compliance with the financial ratio covenants is likely during 2017. As a result of the Company's non-compliance under this Credit Facility, 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. While the lender has provided limited waivers for our past noncompliance, there is no assurance that it will continue to do so if we are non-compliant in the future. Currently, we do not have adequate funding to repay Wells Fargo if it declares our covenant non-compliance to be an event of default or if it elects to reduce the borrowing base below the amount of the outstanding balance. The ongoing availability of this Credit Facility through the maturity date of July 30, 2017, or our receipt of funding from alternative sources, is critical to our ability to survive and continue as a going concern. If we become unable to continue as a going concern, we may find it necessary to liquidate our assets or 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.

On December 16, 2016, the Company entered into a securities purchase agreement, pursuant to which the Company agreed to sell 1,000,000 shares of its of its common stock for gross proceeds of $1.5 million.

During 2015 and 2014, we received significant overpayments due to an operator's failure to timely recognize the payout implications of our joint operating agreements. During the second quarter of 2015, the operator corrected its records and has elected to begin withholding the net revenues from all of our wells that it operates to recover these overpayments. As of December 31, 2016, the balance of the overpayment was approximately $2.7 million and based on the oil and gas prices and costs used in our reserve report as of December 31, 2016, this liability is expected to be settled in late 2017.

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 which amounted to $1.4 million as of December 31, 2016. The ultimate resolution of these uncertainties about our working interests and net revenue interests can extend over a long period of time and we cannot provide any assurance that these matters will be resolved within the next year.

Our standardized measure decreased by $6.7 million during 2016 which was primarily associated with decreases in oil and gas prices. The reduction in our total assets and shareholders' equity is primarily associated with our net loss of $14.1 million during 2016, as discussed under *Results of Operations* herein.

During 2016, we completed the following actions to improve our operating results going forward:

- In February 2016, we completed the disposition of our mining segment, including the Keystone Mine, a related water treatment plant and other related properties. While an impairment charge of $22.6 million was recognized related to this disposition, a significant objective for completing the disposition was to improve future profitability. Following the disposition, we are no longer required to operate the water treatment plant and will not be responsible for mine holding costs, which are expected to result in estimated annual cash savings of $3.0 million. We believe the disposition of our mining segment is a major step in the transformation of the Company to solely focus on our existing oil and gas business.

- In April 2016, our lender provided a limited waiver for our noncompliance with the financial covenants as of December 31, 2015.

- In August 2016, our lender provided the 4 th amendment to our credit facility, providing a limited waiver for our noncompliance with the financial covenants as of June 30, 2016.

As of December 31, 2016, we had cash and equivalents of $2.5 million.

If we have needs for financing in 2017, alternatives that we will consider if necessary include selling or joint venturing an interest in some of our oil and gas assets, selling our real estate assets in Wyoming, selling our marketable equity securities, issuing shares of our common stock for cash or as consideration for acquisitions, and other alternatives, as we determine how to best fund our capital programs and meet our financial obligations.

Any potential capital expenditure plan and our ability to obtain sufficient funding to make anticipated capital expenditures and satisfy our financial obligations are subject to numerous risks and uncertainties, including the risk of continued low commodity prices or further reductions in those prices, the risk that breaches of covenants in our Credit Facility will not be waived and will result in liquidation, bankruptcy or similar proceedings, the risk that we will be unable to enter into additional financing arrangements on acceptable terms or at all, and numerous other risks, including those discussed in *Risk Factors* under Item 1A in this report on Form 10-K.

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2016 and 2015 (in thousands):

	2016	2015	Change
Net cash provided by (used in):			
Operating activities	$ (1,405)	$ 2,504	$ (3,909)
Investing activities	(193)	(565)	372
Financing activities	1,211	(154)	1,365
Discontinued operations	(448)	(2,441)	1,993

Operating Activities. Cash provided by operating activities for the year ended December 31, 2016 was a $1.4 million cash use as compared to cash provided by operating activities of $2.5 million for 2015, a decrease of $3.9 million. This decrease is primarily related to the significant cash impact caused by the reduction in our oil and gas sales, net of production costs, for the year ended December 31, 2016 as compared to 2015.

Investing Activities. Cash generated in investing activities for the year ended December 31, 2016 was a cash use of $0.2 million as compared to cash used in investing activities of $0.6 million for 2015, an improvement of $0.5 million. The sole use of cash in our investing activities for 2016 was associated with funding capital expenditures.

Financing Activities. Cash generated by financing activities for the year ended December 31, 2016 was $1.2 million as compared to cash used in financing activities of $0.1 million for 2015, an improvement of $1.3 million. The primary generation of cash in our financing activities for 2016 was $1.2 million of proceeds from the issuance of common stock, net of offering costs, in December 2016.

Discontinued Operations. Cash used in our discontinued operations was $0.4 million for the year ended December 31, 2016 as compared to $2.4 million for 2014, an improvement of $2.0 million. The improvement was primarily due to the disposition of the Company's mining assets early in 2016.

Off-balance Sheet Arrangements

As part of our ongoing business, we have not participated in transactions that generate relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities (“SPEs”), which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes.

We evaluate our transactions to determine if any variable interest entities exist. If it is determined that we are the primary beneficiary of a variable interest entity, that entity will be consolidated in our consolidated financial statements. We have not been involved in any off-balance sheet arrangements via unconsolidated SPE transactions during the three-year period ended December 31, 2016.

Item 8 – Financial Statements and Supplementary Data

Financial statements meeting the requirements of Regulation S-X are included below.

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Item 9 – Changes In and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A – Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures . We are required to maintain disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) that are designed to ensure that required information is recorded, processed, summarized and reported within the required timeframe, as specified in the rules of the SEC. Our disclosure controls and procedures are also designed to ensure that information required to be disclosed is accumulated and communicated to management, including our Chief Executive Officer and Principal Financial Officer, to allow timely decisions regarding required disclosures.

Based on an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act), as of the end of our fiscal year ended December 31, 2016, our Chief Executive Officer and Principal Financial Officer (both roles are currently held by the same individual) determined that our controls were not adequate due to a vacancy in certain accounting and finance consulting positions that the Company has historically utilized to implement the Company’s review of key controls in a timely manner. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company’s annual or interim financial statements will not be prevented or detected on a timely basis. Accordingly, based on this material weakness, our Chief Executive Officer and Principal Financial Officer concluded that our disclosure controls and procedures were not effective as of the end of the period covered by this Annual Report on Form 10-K, December 31, 2016, as it relates to the timely implementation of the Company’s review of key controls.

This material weakness resulted in no identified misstatements of the consolidated financial statements. The Company has addressed this weakness by filling the consulting vacancy with professionals with experience in implementing a full review of key controls on an ongoing basis.

Managements Report on Internal Control Over Financial Reporting . We are responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act). We maintain a system of internal controls that is designed to provide reasonable assurance in a cost-effective manner as to the fair and reliable preparation and presentation of the consolidated financial statements in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Under the supervision and with the participation of the Company's management, including the Chief Executive Officer and the Principal Financial Officer, the Company's management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2016. In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control-Integrated-Framework" (2013 framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") which. Based on the evaluation conducted under the framework in "Internal Control- Integrated Framework" issued by COSO, the Company's management concluded that the Company's internal control over financial reporting was not effective as of December 31, 2016 for the reasons described above.

This annual report does not include an attestation report of our registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting . Other than the identified material weakness described above and the Company's solution to address the identified material weakness, there have been no other changes to the Company's system of internal control over financial reporting during the year and fiscal quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's system of controls over financial reporting. As part of a continuing effort to improve the Company's business processes, management is currently evaluating its internal controls and may update certain controls to accommodate any modifications to its business processes or accounting procedures.

Item 9B – Other Information

None

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
U.S. Energy Corp.

We have audited the accompanying consolidated balance sheets of U.S. Energy Corp. and subsidiary as of December 31, 2016 and 2015, and the related consolidated statements of operations and comprehensive loss, stockholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of U.S. Energy Corp. and subsidiary as of December 31, 2016 and 2015, and the results of their operations and their cash flows for the years then ended, in conformity with U.S. generally accepted accounting principles.

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 2 to the financial statements, the Company has a working capital deficit, an accumulated deficit, and has incurred recurring losses from operations. The Company is in default of its loan covenants for the year ending December 31, 2016 and is expected to remain out of compliance through maturity of the loan. Accordingly, the entire balance has been classified as a current liability as of December 31, 2016. While the lender has provided limited waivers for the Company's past noncompliance, there is no assurance that it will continue to do so in the future. These factors raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters also are described in Note 2. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Hein & Associates LLP

Denver, Colorado
April 17, 2017

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2016 AND 2015
(In Thousands, Except Share and Per Share Amounts)

	2016	2015
ASSETS		
Current assets:		
Cash and equivalents	$ 2,518	$ 3,354
Oil and gas sales receivable	562	1,143
Oil price risk derivatives	-	1,634
Discontinued operations - assets of mining segment	114	318
Assets available for sale	653	251
Other current assets	1,042	136
Total current assets	4,889	6,836
Oil and gas properties under full cost method:		
Unevaluated properties and exploratory wells in progress	4,664	5,664
Evaluated properties	87,834	97,912
Less accumulated depreciation, depletion and amortization	(82,640)	(80,144)
Net oil and gas properties	9,858	23,432
Other assets:		
Property and equipment, net	1,864	2,658
Other assets	156	206
Total other assets	2,020	2,864
Total assets	$ 16,767	$ 33,132
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities:		
Payable to Major Operator	$ 2,710	$ 4,159
Contingent ownership interests	1,430	3,108
Other	743	1,775
Accrued compensation and benefits	49	1,352
Current portion of long-term debt	6,000	6,000
Discontinued operations of mining properties	-	204
Other current liabilities	-	16
Total current liabilities	10,932	16,614
Noncurrent liabilities:		
Long-term debt, less current portion	-	-
Asset retirement obligations	1,045	1,038
Warrant Liability	1,030	-
Other liabilities	2	5
Total noncurrent liabilities	2,077	1,043
Commitments and contingencies (Note 10)		
Shareholders' equity:		
Preferred stock, par value $0.01 per share. Authorized 100,000 shares, 50,000 shares of series A Convertible Preferred Stock in 2016; liquidation preference of 2,232 as of December 31, 2016.	1	-
Common stock, $0.01 par value; unlimited shares authorized; 6,134,506 and 4,699,956 shares issued and outstanding, respectively	61	282
Additional paid-in capital	127,576	124,898
Accumulated deficit	(123,825)	(109,705)
Other comprehensive loss	(55)	-
Total shareholders' equity	3,758	15,475
Total liabilities and shareholders' equity	$ 16,767	$ 33,132

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014
(In Thousands, Except Share and Per Share Amounts)

	2016	2015	2014
Revenue:			
Oil	$ 4,689	$ 9,047	$ 28,331
Natural gas and liquids	1,057	1,249	4,048
Total revenue	5,746	10,296	32,379
Operating expenses:			
Oil and gas operations:			
Production costs	2,728	7,352	10,638
Depreciation, depletion and amortization	2,529	8,412	14,685
Impairment of oil and gas properties	9,568	57,676	-
General and administrative:			
Compensation and benefits, including directors and contract employees	640	2,602	4,124
Stock-based compensation	213	948	527
Employee severance costs	3	504	-
Professional fees, insurance and other	1,994	1,866	1,785
Total operating expenses	17,675	79,360	31,759
Operating Gain/(loss)	(11,929)	(69,064)	620
Other income (expense):			
Realized gain (loss) on oil price risk derivatives	1,440	(75)	316
Unrealized gain (loss) on oil price risk derivatives	(1,634)	1,634	266
Gain on sale of assets	102	121	112
Gain (loss) on investments	750	(68)	-
Rental and other income (loss)	(169)	431	88
Warrant revaluation gain	210	-	-
Interest expense	(442)	(263)	(385)
Total other income (expense)	257	1,780	397
Income/(loss) from continuing operations	(11,672)	(67,284)	1,017
Discontinued operations:			
Discontinued operations	(2,448)	(2,992)	(3,108)
Impairment loss on discontinued operations	-	(22,620)	-
Loss from discontinued operations	(2,448)	(25,612)	(3,108)
Net loss	**(14,120)**	**(92,896)**	**(2,091)**
Change in fair value of marketable equity securities	(55)	56	(44)
Comprehensive loss	$ (14,175)	$ (92,840)	$ (2,135)
Loss from continuing operations applicable to common shareholders			
Loss from continuing operations	(11,672)	(67,284)	1,017
Accrued dividends related to Series A Convertible Preferred Stock	(232)	-	-
Loss from continuing operations applicable to common shareholders	(11,904)	(67,284)	1,017
Net loss	(14,120)	(67,284)	1,017
Accrued dividends related to Series A Convertible Preferred Stock	(232)	-	-
Net loss applicable to common shareholders	(14,352)	(67,284)	1,017
Loss per share- basic and diluted			
Continuing operations	$ (2.50)	$ (14.38)	$ 0.04

Discontinued operations	(0.51)	(5.48)	(0.12)
Total	$ (3.01)	$ (19.86)	$ (0.08)
Weighted average shares outstanding			
Basic and diluted	4,768,013	4,677,500	4,638,833

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014
(In Thousands, Except Share Amounts)

	Common Stock		Preferred Stock		Additional Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total
	Shares	Amount	Shares	Amount				
Balances, December 31, 2013	4,622,646	46	-	-	123,741	(14,718)	(12)	109,057
Stock-based compensation	-	-	-	-	318	-	-	318
Exercise of employee stock options	26,325	-	-	-	(62)	-	-	(62)
Exercise of stock purchase warrants	2,019	-	-	-	8	-	-	8
Issuance of common stock to fund ESOP contribution	23,620	1	-	-	208	-	-	209
Unrealized loss on marketable equity securities	-	-	-	-	-	-	(44)	(44)
Net loss	-	-	-	-	-	(2,091)	-	(2,091)
Balances, December 31, 2014	4,674,610	47	-	-	124,213	(16,809)	(56)	107,395
Issuance of common stock upon vesting of restricted common stock, net	25,346	-	-	-	332	-	-	332
Stock-based compensation	-	-	-	-	588	-	-	588
Realized loss on marketable equity securities	-	-	-	-	-	-	56	56
Net loss	-	-	-	-	-	(92,896)	-	(92,896)
Balances, December 31, 2015	4,699,956	$ 47	-	-	$ 125,133	$ (109,705)	$ -	15,475
Issuance of common stock	367,667	3	-	-	(3)	-	-	-
Cash payment for fractional shares	(1,245)	-	-	-	(3)	-	-	(3)
Stock-based compensation	-	-	-	-	213	-	-	213
Issuance of common shares on 7/7/16 to settle ESOP	68,128	1	-	-	169	-	-	170
Issuance of common shares	1,000,000	10	-	-	68	-	-	78
Issuance of Series A Convertible Preferred Stock	-	-	50,000	1	1,999	-	-	2,000
Unrealized loss on marketable equity securities	-	-	-	-	-	-	(55)	(55)
Net loss	-	-	-	-	-	(14,120)	-	(14,120)
Balances, December 31, 2016	6,134,506	$ 61	50,000	1	$ 127,576	$ (123,825)	$ (55)	3, 758

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014
(In Thousands)

	2016	2015	2014
Cash flows from operating activities:			
Net loss	$ (14,120)	$ (92,896)	$ (2,091)
Loss from discontinued operations	2,448	25,612	3,108
Loss from continuing operations	(11,672)	(67,284)	(1,017)
Adjustments to reconcile loss from continuing operations to net cash provided by/(used in) operating activities:			
Depreciation, depletion and amortization	2,259	8,557	14,833
Impairment of oil and gas properties	9,568	57,676	-
Change in fair value of oil price risk derivative	1,634	(1,634)	(266)
Interest change in Major Operator	(1,476)	-	-
Gain on sale of assets	(102)	(121)	(112)
Stock-based compensation and services	213	948	527
Gain on Warrants	(210)	-	-
Other	(372)	(110)	585
Changes in operating assets and liabilities:			
Decrease (increase) in:			
Oil and gas sales receivable	580	2,034	(2,571)
Other assets	86	63	165
Increase (decrease) in:			
Accounts payable	(1,050)	1,126	909
Oil and gas operator overpayments	-	1,429	3,983
Accrued compensation and benefits	(1,133)	(188)	(436)
Other liabilities	-	(8)	(39)
Net cash provided by/(used in) operating activities	(1,405)	2,504	23,737
Cash flows from investing activities:			
Capital expenditures	(193)	(3,620)	(31,044)
Proceeds from sale of oil and gas properties and other		264	11,624
Proceeds from settlement of property litigation	-	1,500	-
Net change in restricted investments	-	(1,291)	(122)
Net cash used in investing activities:	(193)	(565)	(19,542)
Cash flows from financing activities:			
Issuance of common stock and warrants	1,317	-	-
Redemption of common stock	(3)	(29)	(55)
Proceeds from debt financings	-	-	8,000
Principal payments under debt financings	-	-	(11,000)
Payments for debt issuance costs	(103)	(125)	-
Net cash provided by/(used in) financing activities	1,211	(154)	(3,055)
Discontinued operations:			
Net cash used in operating activities	(448)	(2,440)	(2,985)
Net cash used in investing activities	-	(1)	-
Net cash used in discontinued operations	(448)	(2,441)	(2,985)
Net decrease in cash and equivalents	(835)	(656)	(1,845)
Cash and equivalents, beginning of year	3,354	4,010	5,855
Cash and equivalents, end of year	$ 2,518	$ 3,354	$ 4,010
ARO and mining properties disposal	(1)	-	-
Net non-cash activities	(1)	-	-

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, Continued
FOR THE YEARS ENDED DECEMBER 31, 2016, 2015 AND 2014
(In Thousands)

	2016	2015	2014
Supplemental disclosures of cash flow information:			
Cash payments for income taxes	$ -	$ -	$ -
Cash payments for interest	$ 442	$ 210	$ 385
Non-cash investing and financing activities:			
Unrealized gain/(loss) on marketable equity securities	$ (55)	$ 56	$ (44)
Increase (decrease) in accrued capital expenditures for oil and gas properties	$ 112	$ (112)	$ (2,565)
Net additions to oil and gas properties through asset retirement obligations	$ -	$ 61	$ 281

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

1. ORGANIZATION, OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Organization and Operations

U.S. Energy Corp. (collectively with its subsidiaries Energy One LLC, Highlands Ranch LLC, and Remington Village, LLC referred to as the "Company") was incorporated in the State of Wyoming on January 26, 1966. The Company's principal business activities are focused in the acquisition, exploration and development of oil and gas properties in the United States.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States ("U.S. GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves that are used in the calculation of depreciation, depletion, amortization and impairment of the carrying value of evaluated oil and gas properties; production and commodity price estimates used to record accrued oil and gas sales receivable; valuation of commodity derivative instruments; the impact of commodity prices and other events affecting impairment of mining properties; and the cost of future asset retirement obligations. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable. Due to inherent uncertainties, including the future prices of oil and gas, these estimates could change in the near term and such changes could be material.

Principles of Consolidation

The accompanying financial statements include the accounts of the Company and its wholly-owned subsidiary Energy One LLC ("Energy One"). All inter-company balances and transactions have been eliminated in consolidation. Certain prior period amounts have been reclassified to conform to the current period presentation of the accompanying financial statements.

Cash and Equivalents

The Company considers all highly liquid investments with original maturities of three months or less to be cash equivalents.

Oil and Gas Sales Receivable

The Company's accounts receivable consist primarily of receivables from joint interest operators for the Company's share of oil, gas, and natural gas liquids ("NGLs"). Generally, the Company's oil and gas sales receivable are collected within three months and the Company has had minimal bad debts. Collectability is dependent upon the financial wherewithal of the joint interest operators and is influenced by the general economic conditions of the industry. Receivables are not collateralized. As of December 31, 2016 and 2015, the Company had not provided for an allowance for doubtful accounts.

Marketable Equity Securities

The Company categorizes its marketable equity securities as available-for-sale. Accordingly, increases or decreases in the fair value are generally presumed to be temporary and are recorded as a component of shareholders' equity within comprehensive income or loss. The Company periodically evaluates if cumulative losses are indicative of other than temporary impairment whereby a loss is recognized when management determines that the value is unlikely to recover to the Company's cost basis. Gains or losses from sales are recorded in operations when realized.

Oil and Gas Properties

The Company follows the full cost method of accounting for its oil and gas properties. 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 property 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 are subject to depreciation, depletion and amortization ("DD&A") using the equivalent unit-of-production method, based on total proved oil and gas reserves. For financial statement presentation, DD&A includes accretion expense related to asset retirement obligations. Excluded from amounts subject to DD&A are costs associated with unevaluated properties, including exploratory wells in progress.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability, or the cost center ceiling (the "Ceiling Test"). 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 average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period; and costs, adjusted for contract provisions and financial derivatives that hedge the Company's oil and gas revenue and asset retirement obligations, (ii) the cost of unevaluated properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, reduced by (iv) the income tax effects related to differences between the book and tax basis of the crude oil and gas properties. If the net book value reduced by the related net deferred income tax liability (if any) 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. Since all of the Company's oil and gas properties are located within the United States, the Company only has one cost center for which a quarterly Ceiling Test is performed.

Property and Equipment

Land, buildings, improvements, machinery and equipment are carried at cost. Depreciation of buildings, improvements, machinery and equipment is provided principally by the straight-line method over estimated useful lives as follows:

	Years
Real estate:	
Buildings	20 to 45
Building improvements	10 to 25
Land improvements	10 to 35
Administrative assets:	
Computers and software	3 to 10
Office furniture and equipment	5 to 20
Vehicles and other	5

Discontinued Operations- Mining Properties

Effective January 1, 2015, the Company adopted new accounting guidance related to the recognition and presentation of discontinued operations in its financial statements. Under the revised guidance, beginning in 2015 only disposals of businesses that represent strategic shifts that have a major effect on an organization's operations and financial results will be reported in discontinued operations. Accordingly, as discussed in Note 6, the Company's disposal of its mining segment qualified for reporting as discontinued operations in the accompanying financial statements.

The Company capitalized all costs incidental to the acquisition of mining properties. Mining equipment was depreciated using the straight line method over estimated useful lives that ranged from 10 to 20 years. Costs of operating a related water treatment plant on the mine property, holding costs to maintain permits, mining exploration costs and general corporate overhead were expensed as incurred. Capitalized costs were charged to operations to the extent it was subsequently determined that the mine property is not economic due to permanent decreases in market prices of commodities, excessive production costs, depletion of the mineral resource, or other factors.

Long-Lived Assets

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the related carrying amount may not be recoverable. If estimated future cash flows, on an undiscounted basis, are less than the carrying amount of the related asset, an asset impairment charge is recognized, and measured as the amount by which the carrying value exceeds the estimated fair value. Changes in significant assumptions underlying future cash flow estimates may have a material effect on the Company's financial position and results of operations.

Long-lived assets are classified as held for sale when the Company commits to a plan to sell the assets. Such assets are classified within current assets if there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to determine if there is any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets.

Derivative Instruments

The Company uses derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk underlying its oil and gas production. All derivative instruments are recorded in the consolidated balance sheets at fair value. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty. Although the Company does not designate any of its derivative instruments as cash flow hedges, such derivative instruments provide an economic hedge of the Company's exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, the Company recognizes all unrealized and realized gains and losses that are related to these contracts currently in earnings and classifies them as gain (loss) on derivative instruments, net in the Company's consolidated statements of operations. The Company may also use puts, calls and basis swaps in the future.

Warrant Liability

From time to time we may have financial instruments such as warrants that may be classified as liabilities when either (a) the holders possess rights to net cash settlement, (b) physical or net equity settlement is not in our control, or (c) the instruments contain other provisions that causes us to conclude that they are not indexed to our equity. Such instruments are initially recorded at fair value and subsequently adjusted to fair value at the end of each reporting period through earnings. Accordingly, warrants are accounted for as a liability. This warrant liability is accounted for at fair value with changes in fair value reported in earnings.

Asset Retirement Obligations

The Company records the estimated fair value of restoration and reclamation liabilities related to its oil and gas properties and its inactive mining properties as of the date that the liability is incurred. The Company reviews the liability each quarter and determines if a change in estimate is required, and accretion of the discounted liability is recorded based on the passage of time. Final determinations are made during the fourth quarter of each year. The Company deducts any actual funds expended for restoration and reclamation during the quarter in which it occurs.

Revenue Recognition

The Company derives revenue primarily from the sale of produced oil, natural gas, and NGLs. In the accompanying statements of operations, revenue from gas includes sales of both natural gas and NGLs. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported separately as expenses and are included in lease operating expense in the accompanying statements of operations. The Company records oil and gas revenue under the sales method of accounting. Gas balancing obligations as of December 31, 2016 and 2015 were not significant. Revenue is recorded in the month that the production is delivered to the purchaser. At the end of each month, the Company estimates the amount of production delivered to the purchaser and the price the Company will receive. The Company uses its knowledge of its properties, their historical performance, market prices, and other factors as the basis for these estimates.

Revenues from real estate operations are reported on a gross revenue basis and are recorded at the time the service is provided.

Stock-Based Compensation

The Company measures the cost of employee and director services received in exchange for all equity awards granted, including stock options, based on the fair market value of the award as of the grant date. The Company computes the fair values of its options granted to employees using the Black Scholes pricing model. The Company recognizes the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. For awards granted which contain a graded vesting schedule, and the only condition for vesting is a service condition, compensation cost is recognized as an expense on a straight-line basis over the requisite service period as if the award was, in substance, a single award. Stock-based compensation expense is recognized based on awards ultimately expected to vest whereby estimates of forfeitures are based upon historical experience.

Income Taxes

The Company recognizes deferred income tax assets and liabilities for the expected future income tax consequences, based on enacted tax laws, of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

Additionally, the Company recognizes deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. At December 31, 2016 and 2015, management believed it was more likely than not that such tax benefits would not be realized and a valuation allowance has been provided. The Company would recognize any interest and penalties related to uncertain tax positions as a component of income tax expense.

Earnings Per Share

Basic net income (loss) per share is computed based on the weighted average number of common shares outstanding. Diluted net income (loss) per share is calculated by dividing net income or loss by the diluted weighted average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options. When there is a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are excluded from the calculation of net income (loss) per share. The treasury stock method is used to measure the dilutive impact of in-the-money stock options.

Comprehensive Income (Loss)

Comprehensive income (loss) is used to refer to net income (loss) plus other comprehensive income (loss). Other comprehensive income (loss) is comprised of revenues, expenses, gains, and losses that under GAAP are reported as separate components of shareholders' equity instead of net income (loss).

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers". This comprehensive guidance will replace all existing revenue recognition guidance and is effective for annual reporting periods beginning after December 15, 2017, and interim periods therein. This update is not expected to have a significant impact on the Company's financial statements.

In August 2014, the FASB issued ASU No. 2014-15, "Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern" that will require management to evaluate whether there are conditions and events that raise substantial doubt about the Company's ability to continue as a going concern within one year after the financial statements are issued on both an interim and annual basis. Management will be required to provide certain footnote disclosures if it concludes that substantial doubt exists or when its plans alleviate substantial doubt about the Company's ability to continue as a going concern. This ASU becomes effective for annual periods beginning in 2016 and for interim reporting periods starting in the first quarter of 2017. This update did not have a significant impact on the Company's financial statements.

In November 2014, the FASB issued ASU 2014-16, "Derivatives and Hedging: Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity". This ASU does not change the current criteria in GAAP for determining when separation of certain embedded derivative features in a hybrid financial instrument is required, but clarifies how current GAAP should be interpreted in the evaluation of the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share, reducing existing diversity in practice. This ASU became effective for interim periods beginning on January 1, 2016. This update did not have a significant impact on the Company's financial statements.

In January 2015, the FASB issued ASU 2015-01, "Income Statement—Extraordinary and Unusual Items", that will simplify income statement classification by removing the concept of extraordinary items from GAAP. Upon adoption, the separate disclosure of extraordinary items after income from continuing operations in the income statement will no longer be permitted. The Company adopted this standard as of January 1, 2016. This update did not have a significant impact on the Company's financial statements.

In February 2015, the FASB issued ASU No. 2015-02, "Consolidation: Amendments to the Consolidation Analysis". The new standard is intended to improve targeted areas of consolidation guidance for legal entities such as limited partnerships, limited liability corporations, and securitization structures. The new guidance must be adopted for interim and annual financial statements issued for the year ending December 31, 2016. The adoption of this standard did not have a material impact on the Company's consolidated financial statements.

During 2015, the FASB issued ASUs No. 2015-03 and No. 2015-15 titled "Interest-Imputation of Interest", which generally requires the presentation of debt issuance costs as a direct deduction from the carrying amount of the related debt liabilities. However, for debt issuance costs related to line-of-credit arrangements, the Company will be permitted to continue presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement. The Company does not have any outstanding deferred lines of credit at this time.

In January 2016, the FASB issued ASU 2016-01, Financial Instruments - Overall: Recognition and Measurement of Financial Assets and Financial Liabilities. This ASU is intended to improve the recognition and measurement of financial instruments. Among other things, this ASU requires certain equity investments to be measured at fair value with changes in fair value recognized in net income. This guidance is effective for fiscal years beginning after December 15, 2017, and interim periods therein.

In February 2016, the FASB issued ASU 2016-02, Leases, which will supersede the existing guidance for lease accounting. This ASU will require lessees to recognize leases on their balance sheets, and leaves lessor accounting largely unchanged. This guidance is effective for fiscal years beginning after December 15, 2018 and interim periods within those fiscal years, and early adoption is permitted. This update did not have a significant impact on the Company’s financial statements.

2016-05
In March 2016, the FASB issued ASU 2016-06 *, Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments.* The amendments clarify the steps required to assess whether a call or put option meets the criteria for bifurcation as an embedded derivative. The amendment is effective for fiscal years and interim periods beginning after December 1, 2016. This amendment is not expected to have a significant impact on the Company’s financial statements.

2016-06
In March 2016, the FASB issued ASU 2016-06 *, Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments.* The amendments clarify the steps required to assess whether a call or put option meets the criteria for bifurcation as an embedded derivative. The amendment is effective for fiscal years and interim periods beginning after December 1, 2016. This amendment is not expected to have a significant impact on the Company’s financial statements.

2016-11
In May 2016, the FASB issued ASU No. 2016-11, *Revenue Recognition* (Topic 605) and *Derivatives and Hedging* (Topic 815): Rescission of SEC Guidance Because of Accounting Standards Updates 2014-09 and 2014-16 Pursuant to Staff Announcements at the March 3, 2016 EITF Meeting ("ASU 2016-11"). The SEC Staff is rescinding the following SEC Staff Observer comments that are codified in Topic 605, Revenue Recognition, and Topic 932, Extractive Activities-Oil and Gas, effective upon adoption of Topic 606. Specifically, registrants should not rely on the following SEC Staff Observer comments upon adoption of Topic 606: a) Revenue and Expense Recognition for Freight Services in Process which is codified in 605-20-S99-2; b) Accounting for Shipping and Handling Fees and Costs, which is codified in paragraph 605-45-S99-1; c) Accounting for Consideration Given by a Vendor to a Customer, which is codified in paragraph 605-50-S99-1 and d) Accounting for Gas-Balancing Arrangements (that is, use of the “entitlements method”), which is codified in paragraph 932-10-S99-5. We do not use the entitlements method of accounting and are not impacted by this specific SEC Staff Observer comment; however, we are assessing the potential impact of other SEC Staff Observer comments included in ASU 2016-11 on our consolidated financial condition and results of operations.

2016-15
In August 2016, the FASB issued ASU No. 2016-15, *Statement of Cash Flows* (Topic 230) *: Classification of Certain Cash Receipts and Cash Payments* ("ASU 2016-15"). ASU 2016-15 reduces diversity in practice in how certain transactions are classified in the statement of cash flows. The amendments in ASU 2016-15 provide guidance on specific cash flow issues including debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and distributions received from equity method investees. ASU 2016-15 is effective for annual and interim periods beginning after December 15, 2017. We are currently assessing the potential impact of ASU 2016-15 on our consolidated financial condition and results of operations.

2016-18

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash (a consensus of the FASB Emerging Issues Task Force)* ("ASU 2016-18"). The amendments in this update require that a statement of cash flows explain the change during the period in total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. Therefore, amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows. ASU 2016-18 is effective for annual and interim periods beginning after December 15, 2017 and early adoption is permitted. The Company is currently assessing the impact of ASU 2016-18 on our consolidated financial condition and results of operations .

2017-03

In January 2017, the FASB issued ASU No. 2017-03, *Accounting Changes and Error Corrections* (Topic 250) *and Investments – Equity Method and Joint Ventures* (Topic 323), which stated additional qualitative disclosures should be considered to assess the significance of the impact upon adoption. This ASU is effective for the annual period beginning after December 15, 2018, and for annual and interim periods thereafter. Early adoption is permitted. The Company is currently evaluating the new guidance to determine the impact it will have on its consolidated financial condition and results of operations.

2017-04

In January 2017, the FASB issued ASU No. 2017-04, *Intangibles - Goodwill and Other* (Topic 350): *Simplifying the Test for Goodwill Impairment* ("ASU 2017-04"). ASU 2017-04 eliminates Step 2 of the goodwill impairment test. Instead, an entity should perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. ASU 2017-04 is effective for annual and interim periods beginning after December 15, 2019 and early adoption is permitted for interim or annual goodwill impairment tests performed after January 1, 2017. We are currently assessing the impact of ASU 2017-04 and date of adoption.

2017-05

In February 2017, the FASB issued Update No. 2017-05, *Other Income-Gains and Losses from the Derecognition of Nonfinancial Assets* (Subtopic 610-20): *Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets* . This update is meant to clarify the scope of ASC Subtopic 610-20, Other Income-Gains and Losses from the Derecognition of Nonfinancial Assets and to add guidance for partial sales of nonfinancial assets. This guidance is to be applied using a full retrospective method or a modified retrospective method as outlined in the guidance and is effective at the same time as Update 2014-09. Further, the Company is required to adopt this guidance at the same time that it adopts the guidance in Update 2014-09. The Company is currently evaluating the provisions of this guidance and assessing its potential impact on the Company's financial condition and results of operations.

2. LIQUIDITY

As of December 31, 2016, the Company has a working capital deficit of $6,042 and an accumulated deficit of $124,035. Additionally, the Company incurred a net loss of $14.1 million for the year ended December 31, 2016. During 2016, the Company was in violation of certain covenants in its credit agreement and the Company expects future violations in 2017, which requires the entire balance to be classified as a current liability. While the lender has provided limited waivers for the Company's past noncompliance, there is no assurance that it will continue to do so in the future.

During the 2016, the Company completed the following actions which are expected to improve the Company's operating results in 2017 and increase the ability of the Company to survive the current oil and gas industry price environment.

- In February 2016 the Company completed the disposition of its mining segment, including the Keystone Mine, a related water treatment plant and other related properties. While an impairment charge of $22,620 was recognized related to this disposition, a significant objective for completing the disposition was to improve future profitability. Following the disposition, the Company is no longer required to operate the water treatment plant and will not be responsible for mine holding costs, which are expected to result in estimated annual cash savings of $3,000. Management believes the disposition of the Company's mining segment is a major step in the transformation of U.S. Energy Corp. to solely focus on its existing oil and gas business.

- On December 21, 2016, the Company completed a registered direct offering of 1,000,000 shares of common stock at a net price of $1.50 per share. Concurrently, the investors received warrants to purchase 1,000,000 shares of Common Stock of the Company at an exercise price of $2.05 per share, subject to adjustment, for a period of five years from closing. The total net proceeds received by the Company was approximately $1.32 million. The fair value of the warrants upon issuance was $1.24 million, with the remaining $0.08 million being attributed to common stock. The warrants contain a dilutive issuance and other liability provisions which cause the warrants to be accounted for as a liability. Such warrant instruments are initially recorded as a liability and are accounted for at fair value with changes in fair value reported in earnings.

As of December 31, 2016, the Company had cash and equivalents of $2.5 million. Management also expects potential investors and lenders may find the Company's new singular industry focus, combined with attractive producing properties and a low-cost overhead structure, make the Company an attractive vehicle to partner with during this industry downturn and low commodity price environment provided that the Company is able to address the challenges posed by the upcoming maturity of its Wells Fargo Credit Facility on July 30, 2017.

3. OIL PRICE RISK DERIVATIVES

The Company's wholly-owned subsidiary Energy One has entered into crude oil derivative contracts ("economic hedges") with Wells Fargo, the Company's lender as discussed further in Note 7. The derivative contracts are priced based on West Texas Intermediate ("WTI") quoted prices for crude oil. The Company is a guarantor of Energy One's obligations under the economic hedges. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of the Company's future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage the Company's exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit the Company's ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its existing positions. The Company does not engage in speculative derivative activities or derivative trading activities, nor does it use derivatives with leveraged features. As of December 31, 2016, the Company did not have any outstanding crude oil derivative contracts.

Unrealized gains and losses resulting from derivatives are recorded at fair value on the consolidated balance sheet and changes in fair value are included in unrealized gain (loss) on oil price risk derivatives in the consolidated statements of operations.

4. OIL AND GAS PRODUCING ACTIVITIES

Acquisitions

In May 2014, the Company entered into a Participation Agreement to acquire a 33% interest in approximately 12,100 gross (3,384 net) acres in Dimmit County, Texas. The Company's share of the acreage consists of 4,020 gross (1,181 net) acres of primary leasehold acreage and 8,080 gross (2,203 net) acres of farm-in acreage, to be earned through a continuous drilling program. The farm-in acreage had an initial two well commitment and a 12.5% carried working interest for the leaseholder (the "Farmor") in the first 10 wells. After 100% payout of all costs for the first 10 wells that are drilled under the farm-in program, the Farmor will back in for its 12.5% retained working interest in the prospect. The Seller also retained a 25% back-in working interest after 115% of project payout has been received by the Company. The Company paid approximately $3,900 to enter into the transaction, which included leasehold and farm-in acquisition costs as well as a proportionate share of drilling costs for the initial test well in the prospect. As of December 31, 2016, approximately $252 is included in unevaluated properties and the remainder of the costs are included in evaluated properties.

Divestitures

In May 2014, the Company entered into an agreement to sell some of its Williston Basin assets. Under the terms of the agreement, the Company sold its interest in approximately 286 net acres and 16 gross (0.62 net) producing wells in Williams and McKenzie Counties, North Dakota. The transaction closed in June 2014 with an effective date of January 1, 2014. The Company received approximately $12,200 at closing which included $681 in adjustments related to revenue receivable and accounts payable through the date of closing. The balance of the sale proceeds of approximately $11,500 was recorded as a reduction of evaluated properties in the full cost pool.

As discussed in Note 10, in April 2015 the Company settled a quiet title action that was initiated in October 2013, whereby the Company received $1,500 in exchange for releasing its interest in the subject lease. Accordingly, the proceeds from the settlement were accounted for as a reduction of the Company's evaluated oil and gas properties in 2015.

Ceiling Test and Impairment

The reserves used in the Ceiling Test incorporate assumptions regarding pricing and discount rates over which management has no influence in the determination of present value. In the calculation of the Ceiling Test for the year ended December 31, 2016, the Company used $42.75 per barrel for oil and $2.48 per MMbtu for natural gas (as further adjusted for property specific gravity, quality, local markets and distance from markets) to compute the future cash flows of the Company's producing properties. The discount factor used was 10%.

For the years ended December 31, 2016 and 2015, impairment of the Company's oil and gas properties amounted to $9.6 million and $57.7 million, respectively. These impairment charges were primarily due to a decline in the price of oil, additional capitalized well costs and changes in production. Recent declines in the price of oil have significantly increased the risk of Ceiling Test write-downs in future periods.

Capitalized Costs

The following table presents the Company's capitalized costs associated with oil and gas producing activities as of December 31, 2016 and 2015:

	2016	2015
Oil and Gas Properties		
Unevaluated properties:		
Unproved leasehold costs	$ 4,664	$ 5,664
Exploratory wells in progress	-	-
Evaluated properties in full cost pool	87,834	97,912
Less accumulated depreciation, depletion and amortization	(82,640)	(80,144)
Net capitalized costs	$ 9,858	$ 23,432

The Company's depreciation, depletion and amortization per equivalent BOE was $11.93 for 2016, $26.80 for 2015, and $31.56 for 2014.

Unevaluated Oil and Gas Properties

Unevaluated oil and gas properties consist of leasehold costs and exploratory wells in progress which are excluded from the DD&A calculation and the Ceiling Test until a determination about the existence of proved reserves can be completed. As of December 31, 2016, unevaluated oil and gas properties consisted solely of unproved lease acquisition costs of $4.7 million. As of December 31, 2015, unevaluated oil and gas properties consisted solely of unproved lease acquisition costs of $5.7 million.

	As of December 31,	
	2016	2015
Year Incurred		
2010	$ -	$ -
2011	2,686	2,686
2012	267	267
2013	525	1,525
2014	1,153	1,153
2015	33	33
2016	0	
	$ 4,664	$ 5,664

During the fourth quarter of 2015, the Company transferred approximately $2,500 of unproved properties that were considered to be impaired into the full cost pool. On a quarterly basis, management reviews market conditions and other changes in circumstances related to the Company's unevaluated properties and transfers the costs to evaluated properties within the full cost pool as warranted.

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities, all of which have been capitalized, are summarized as follows for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
Acquisition costs:			
Proved properties	$ 42	$ 1,658	$ 552
Unproved properties	-	632	4,167
Development costs	(4)	61	8,037
Exploration costs	(1,496)	369	14,791
Total (1)	$ (1,458)	$ 2,720	$ 27,547

(1) Includes amounts related to estimated asset retirement obligations reduction of $(24) and additions $61 for the years ended December 31, 2016 and 2015, respectively. The development costs and exploration costs include a reduction in interest of some wells which in prior years were in dispute.

Results of Operations

Presented below are the results of operations from oil and gas producing activities for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
Oil and gas sales	$ 5,746	$ 10,296	$ 32,379
Production costs	(2,728)	(7,352)	(10,638)
Depreciation, depletion and amortization	(2,529)	(8,412)	(14,685)
Impairment of oil and gas properties	(9,568)	(57,676)	-
Results of operations from oil and gas producing activities	$ (9,079)	$ (63,144)	$ 7,056

5. PROPERTY AND EQUIPMENT, NET

Property and equipment consists of the following as of December 31, 2016 and 2015:

	2016	2015
Real estate:		
Land	$ 380	$ 1,033
Buildings	4,012	4,012
Land improvements	641	641
Administrative assets:		
Computers and software	368	368
Office furniture and equipment	222	220
Vehicles and other	51	51
Total	5674	6,325
Less accumulated depreciation	(3,810)	(3,667)
Real estate and administrative assets, net	$ 1,864	$ 2,658

Depreciation expense related to real estate and administrative assets amounted to $142, $145 and $148 for the years ended December 31, 2016, 2015 and 2014, respectively.

6. DISCONTINUED OPERATIONS

Disposition of Mining Segment

In February 2006, the Company reacquired the Mt. Emmons molybdenum mining properties (the “Property”). The Company has not conducted any extractive mining operations at the Property since its reacquisition but the Company was obligated under existing permits to operate a water treatment plant (“WTP”) and to incur holding costs associated with the retention of the mining properties, which resulted in aggregate annual expenses of approximately $3,000 during each of the three years in the period ended December 31, 2015.

The market price for molybdenum oxide was approximately $11 per pound during 2013 and 2014 with a decrease to approximately $5 per pound by the fourth quarter of 2015. In light of the considerable ongoing costs related to the Property and the deteriorating market for molybdenum, during 2015 the Company began to explore the viability of alternative structures to the development of the Property that could result in a sharing or elimination of the ongoing costs and liabilities.

In February 2016, the Company’s Board of Directors decided to dispose of the Property rather than continuing the Company’s long-term development strategy whereby the Company entered into the following agreements:

A. The Company entered into an Acquisition Agreement (the “Acquisition Agreement”) with Mt. Emmons Mining Company, a subsidiary of Freeport-McMoRan Inc. (“MEM”), whereby MEM acquired the Property which consists of the Mt. Emmons mine site located in Gunnison County, Colorado, including the Keystone Mine, the WTP and other related properties. Under the Acquisition Agreement, MEM replaced the Company as the permittee and operator of the WTP and will discharge the obligation of the Company to operate the WTP from and after the closing in accordance with the applicable permits issued by the Colorado Department of Public Health and Environment. The Company did not receive any cash consideration for the disposition; the sole consideration for the transfer was that MEM assumed the Company’s obligations to operate the WTP and to pay the future mine holding costs for portions of the Property that it desires to retain.

   As a result of the subsequent disposition of the Property as described above, the Company determined that an impairment charge of $22,620 was required to be recorded in the fourth quarter of 2015. Presented below is calculation of the impairment charge:

Net book value of assets conveyed	$ 22,824
Asset retirement obligations assumed by Purchaser	(204)
Impairment charge recognized in 2015	$ 22,620

Under U.S. GAAP, the disposal of a segment is reported as discontinued operations in the Company's financial statements. Presented below are the assets and liabilities associated with the Company's mining segment as of December 31, 2016 and 2015, along with the impact of the impairment charge:

	2016	2015
Assets retained by the Company:		
Performance bonds	$ 114	$ 114
Net assets conveyed to Purchaser:		
Undeveloped mining claims	-	21,942
Mining equipment	-	1,774
Less accumulated depreciation of mining equipment	-	(892)
Less write-down due to impairment	-	(22,620)
Net book value of assets conveyed	-	204
Total assets of discontinued operations	$ 114	$ 318
Asset retirement obligations assumed by Purchaser	$ -	$ 204

B. Concurrent with entry into the Acquisition Agreement and as additional consideration for MEM to accept transfer of the Property, the Company entered into a Series A Convertible Preferred Stock Purchase Agreement (the "Series A Purchase Agreement") with MEM, whereby the Company issued 50,000 shares of newly designated Series A Convertible Preferred Stock (the "Preferred Stock") in exchange for (i) MEM accepting the transfer of the Property and replacing the Company as the permittee and operator of the WTP, and (ii) the payment of $1 to the Company. The Series A Purchase Agreement contains customary representations and warranties on the part of the Company. As contemplated by the Acquisition Agreement and the Series A Purchase Agreement and as approved by the Company's Board of Directors, the Company filed with the Secretary of State of the State of Wyoming Articles of Amendment containing a Certificate of Designations with respect to the Preferred Stock (the "Certificate of Designations"). Pursuant to the Certificate of Designations, the Company designated 50,000 shares of its authorized preferred stock as Series A Convertible Preferred Stock. The Preferred Stock will accrue dividends at a rate of 12.25% per annum of the Adjusted Liquidation Preference (as defined); such dividends are not payable in cash but are accrued and compounded quarterly in arrears. The "Adjusted Liquidation Preference" is initially $40 per share of Preferred Stock for an aggregate of $2,000, with increases each quarter by the accrued quarterly dividend. The Preferred Stock is senior to other classes or series of shares of the Company with respect to dividend rights and rights upon liquidation. No dividend or distribution will be declared or paid on junior stock, including the Company's common stock, (1) unless approved by the holders of Preferred Stock and (2) unless and until a like dividend has been declared and paid on the Preferred Stock on an as-converted basis.

At the option of the holder, each share of Preferred Stock may initially be converted into 13.33 shares of the Company's $0.01 par value Common Stock (the "Conversion Rate") for an aggregate of 666,667 shares. The Conversion Rate is subject to anti-dilution adjustments for stock splits, stock dividends and certain reorganization events and to price-based anti-dilution protections. Each share of Preferred Stock will be convertible into a number of shares of Common Stock equal to the ratio of the initial conversion value to the conversion value as adjusted for accumulated dividends multiplied by the Conversion Rate. In no event will the aggregate number of shares of Common Stock issued upon conversion be greater than 793,349 shares. The Preferred Stock will generally not vote with the Company's Common Stock on an as-converted basis on matters put before the Company's shareholders. The holders of the Preferred Stock have the right to approve specified matters as set forth in the Certificate of Designations and have the right to require the Company to repurchase the Preferred Stock in connection with a change of control.

During the first quarter of 2017, the Company expects to record the fair value of the Preferred Stock based on the initial liquidation preference of $2,000. Since the cash consideration paid by MEM for the Preferred Stock was a nominal amount, the Company expects to record a charge to operations of approximately $2,000 associated with the issuance.

C. Concurrent with entry into the Acquisition Agreement and the Series A Purchase Agreement, the Company and MEM entered into an Investor Rights Agreement, which provides MEM rights to certain information and Board observer rights. MEM has agreed that it, along with its affiliates, will not acquire more than 16.86% of the Company's issued and outstanding shares of Common Stock. In addition, MEM has the right to demand registration of the shares of Common Stock issuable upon conversion of the Preferred Stock under the Securities Act of 1933, as amended.

Combined Results of Operations for Discontinued Operations

The results of operations of the discontinued mining and apartment complex operations are presented separately for all periods presented in the accompanying financial statements. Presented below are the components for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2014
Operating results for apartment complex:			
Rental revenue	$ -	$ -	$ -
Operating expenses	-	-	-
Net earnings for apartment complex	-	-	-
Operating expenses of mining segment:			
Water treatment plant	(254)	(1,737)	(1,875)
Mine property holding costs	(2,194)	(1,133)	(1,110)
Impairment of mining asset	-	(22,620)	-
Depreciation of mine equipment	-	(122)	(123)
Total expenses for mining segment	(2,448)	(25,612)	(3,108)
Total results for discontinued operations	$ (2,448)	$ (25,612)	$ (3,108)

7. DEBT

Energy One, a wholly-owned subsidiary the Company, has a credit facility with Wells Fargo Bank, National Association ("Wells Fargo"). As of December 31, 2016 and 2015, outstanding borrowings under the credit facility amounted to $6,000. As of December 31, 2016 and 2015, the borrowing base was $6,000. Borrowings under the credit facility are collateralized by Energy One's oil and gas producing properties and substantially all of the Company's cash and equivalents. Each borrowing under the agreement has a term of six months, but can be continued at the Company's election through July 2017 if the Company remains in compliance with the covenants under the credit facility. The weighted average interest rate on this debt is 3.20% as of December 31, 2016.

Energy One is required to comply with customary affirmative covenants and with certain negative covenants. The principal negative financial covenants do not permit (i) the interest coverage ratio (EBITDAX to interest expense) to be less than 3.0 to 1; (ii) total debt to EBITDAX to be greater than 3.5 to 1; and (iii) the current ratio to be less than 1.0 to 1.0. EBITDAX is defined in the Credit Agreement as consolidated net income, plus non-cash charges. Additionally, the Credit Agreement prohibits or limits 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. The Company is a guarantor of Energy One's obligations under the Credit Agreement.

In July 2015, the Company and Wells Fargo Bank entered into a third amendment (the "Third Amendment") to the agreement governing the credit facility (as amended, the "Senior Credit Agreement"). The Third Amendment provides for, among other things: (i) a limited waiver with respect to the restricted payments covenant pursuant to which a transfer of $5,000 from Energy One to the Company was permitted in 2015; (ii) a limited waiver of the current ratio covenant as it relates to the fiscal quarters ended June 30, 2015 and September 30, 2015; and (iii) a borrowing base of $7,000, subject to further adjustment from time to time in accordance with the Senior Credit Agreement. In December 2015, Wells Fargo made a further reduction in the borrowing base to $6,000.

In August 2016, the Company and Wells Fargo Bank entered into a fourth amendment (the “Fourth Amendment”) to the agreement governing the Credit Facility. The Fourth Amendment provides for, among other things, a limited waiver of the negative financial covenants for the fiscal quarters ended March 31, 2016 and June 30, 2016.

As of December 31, 2016, Energy One and the Company were not in compliance with any of the financial covenants and are not expected to regain compliance before the maturity of the credit facility on July 30, 2017.

Because the Company projects that it is unlikely that Energy One will regain compliance with all of the financial covenants within the next 12 months, outstanding borrowings of $6,000 are presented as a current liability in the accompanying consolidated balance sheet as of December 31, 2016. In the event that Energy One is unable to obtain an amendment or waiver of the Senior Credit Agreement to address the anticipated future breaches of the financial covenants, and other actual or potential future breaches that may occur, Wells Fargo could elect to declare some or all of the Company’s debt to be immediately due and payable and could elect to terminate its commitment and cease making further loans.

8. EXECUTIVE RETIREMENT AND SEVERANCE

In October 2005, the Board of Directors adopted an Executive Retirement Policy (the “Retirement Plan”) for the benefit of certain executive officers of the Company. To be eligible to participate in the Retirement Plan, the executive officer was required to serve as one of the designated executive officers for at least 15 years, reached the age of 60, and been an employee of the Company on December 31, 2010. Upon retirement, the executive was entitled to cash payments equaling 50% of the greater of (i) the amount of compensation earned as base cash pay on the final regular pay check or (ii) the average annual pay, less all bonuses, received over the last five years of employment with the Company. The Company periodically engaged the services of a third party actuary to determine the estimated liability under the Retirement Plan. Presented below is a summary of changes in the liability for the years ended December 31, 2016 and 2015:

	2016	2015
Balance, beginning of year	$ 583	$ 1,309
Adjustment to fair value	-	45
Payment of retirement benefits	(583)	(694)
Negotiated settlement at discount and other	-	(77)
Balance, end of year	$ 0	$ 583

As of December 31, 2016 and 2015, the current portion of the Company’s liability under the Retirement Plan amounted to $0 and $583, respectively. These amounts are included in accrued compensation and benefits in the accompanying consolidated balance sheets, and the remainder of the liability is included in other long-term liabilities. Total compensation expense under the Retirement Plan for the years ended December 31, 2016 and 2015 was $3 and $45, respectively. In order to fund the Retirement Plan obligation, the Company periodically made cash contributions to a separate trust account that was managed by an independent trustee. As of December 31, 2014, the Company had funded $1,291 in the trust account, which is recorded as other long term assets in the consolidated balance sheet as of December 31, 2014. The trust account was invested in debt and equity securities until December 2015 when the trust was terminated and the investments were liquidated for cash in the amount of $1,271 which was included in cash and equivalents as of December 31, 2015. The Company and the Retirement Plan participants mutually agreed to terminate the Retirement Plan in December 2015, and all obligations were settled through cash payments during the first quarter of 2016.

In connection with the early retirement of the former COO, effective January 1, 2015 the Company entered into a 12-month consulting agreement with an affiliate of the former executive to provide assistance with matters related to the Company's mining properties. The total payments under the consulting agreement amounted to $274, which is included in mine property holding costs within discontinued operations in the accompanying statement of operations for the year ended December 31, 2015.

During 2016, the Company made total payments of $3 for employee severance. During 2015, the Company entered into severance agreements with three former executive officers that provided for total payments of $379. The Company also incurred severance costs of $125 related to other employees of the Company, resulting in total severance expense of $504 for the year ended December 31, 2015.

9. ASSET RETIREMENT OBLIGATIONS

The following is a reconciliation of the changes in the Company's liabilities for asset retirement obligations for the years ended December 31, 2016 and 2015:

	2016		2015	
	Oil and Gas	Mining	Oil and Gas	Mining
Balance, beginning of year	$ 1,038	$ 204	$ 945	$ 188
Accretion of discount	33	-	32	16
Sold/Plugged	(26)	(204)	-	-
Liabilities incurred	-	-	61	-
Balance, end of year	$ 1,045	$ -	$ 1,038	$ 204

As discussed further in Note 6, asset retirement obligations related to the Company's mining segment are presented as discontinued operations in the accompanying balance sheets.

10. COMMITMENTS AND CONTINGENCIES

Commitments

401(k) Plan. The Board of Directors of the Company adopted the U.S. Energy Corp. 401(k) Plan in 2004. The Company matches 50% of an employee's salary deferrals up to a maximum contribution per employee of $4 annually. The Company's contributions are included in compensation and benefits in the accompanying consolidated statements of operations and amounted to $0, $37, and $48 for the years ended December 31, 2016, 2015 and 2014, respectively. The Company cancelled the 401(k) Plan during 2016.

Lessee Operating Leases. In November 2015, the Company took assignment of a lease agreement for office space in Denver, Colorado. The future minimum rental commitment under this sublease requires payments of $59 in 2017, when the sublease expires.

Lessor Operating Leases. The Company is the lessor of portions of an office building in Riverton, Wyoming that used to serve as the Company's corporate headquarters and which are accounted for as operating leases. Rental income under the agreements was $83, $103, and $95 for the years ended December 31, 2016, 2015 and 2014, respectively.

Letter of Credit. In connection with the Company's sublease of office space in Denver, a security deposit was provided in the form of an irrevocable letter of credit for $35. The letter of credit expires in September 2017. Collateral for the letter of credit is a certificate of deposit for $35 that is included in other assets in the accompanying balance sheet as of December 31, 2016.

Contingencies

From time to time, the Company is party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the Company's financial position or results of operations. Following are currently pending legal matters:

North Dakota Properties. On June 8, 2011, Brigham Oil & Gas, L.P. ("Brigham"), as the operator of the Williston 25-36 #1H Well, filed an action in the State of North Dakota, County of Williams, in District Court, Northwest Judicial District, Case No. 53-11-CV-00495 to interplead to the court with respect to the undistributed suspended royalty funds from this well to protect itself from potential litigation. Brigham became aware of an apparent dispute with respect to ownership of the mineral interest between the ordinary high water mark and the ordinary low water mark of the Missouri River. Brigham suspended payment of certain royalty proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Brigham was subsequently sold to Statoil ASA ("Statoil") who assumed Brigham's rights and obligations under this case. The Company owns a working interest, not royalty interest, in this well and no funds have been withheld.

On January 28, 2013, the District Court Northwest Judicial District issued an Order for Partial Summary Judgment holding that the State of North Dakota as part of its title to the beds of navigable waterways owns the minerals in the area between the ordinary high and low watermarks on these waterways, and that this public title excludes ownership and any proprietary interest by riparian landowners. This issue has been appealed to the North Dakota Supreme Court. The Company's legal position is aligned with Brigham, who will continue to provide legal counsel in this case for the benefit of all working interest owners.

The Company is also a party to litigation that seeks to reform certain assignments of mineral interests it acquired from Brigham. This matter involves the depth below the surface to which the assignments were effective. The plaintiff is seeking to reform the agreement such that the Company's assignment would be revised to be 12 feet closer to the surface. This dispute affects one of the Company's producing wells.

The ultimate outcome of these matters cannot presently be determined. However, in management's opinion the likelihood of a material adverse outcome is remote. Accordingly, adjustments, if any, that might result from the resolution of this matter have not been reflected in the accompanying consolidated financial statements.

Quiet Title Actions. In October 2013, Dimmit Wood Properties, Ltd. ("Dimmit") filed a Quiet Title Action against Chesapeake Exploration, LLC ("Chesapeake"), Crimson Exploration Operating, Inc. ("Crimson"), EXCO Operating Company, LP, OOGC America, Inc., Energy One and Liberty Energy, LLC ("Liberty") (jointly referred to as "Defendants") concerning an 801 gross acre oil and gas lease ("Lease") located in Dimmit County, Texas. Crimson, Energy One and Liberty received an assignment from Chesapeake of the Lease, in which Energy One had a 30% working interest. Dimmit alleged that the Lease terminated due to the failure to achieve production in paying quantities and for having non-existent production for allegedly significant time periods. In April 2015, the Company, Crimson and Liberty agreed to settle the action whereby the Company received $1,500 in exchange for releasing its interest in the subject lease. Accordingly, the proceeds from the settlement were accounted for as a reduction of the Company's evaluated oil and gas properties in 2015.

In September 2013, the Company acquired from Chesapeake a 15% working interest in approximately 4,244 gross mineral acres referred to as the Willerson lease. In January 2014, Willerson inquired if their lease had terminated due to the failure to achieve production in paying quantities pursuant to the terms of the lease. The Company along with Crimson and Liberty filed a declaratory judgment action in the District Court of Dimmit County in May 2014 seeking a determination from the court that the lease remains valid and in effect. The lessors counterclaimed for breach of contract, trespass, and related causes of action. In January 2016, the lessors filed a third-party petition alleging breach of contract, trespass, and related causes of action against Chesapeake and EXCO Operating Company, LP. As of December 31, 2016, unevaluated oil and gas properties includes $1,171 related to the leasehold costs that are subject to this matter. Adjustments, if any, that might result from the resolution of this matter have not been reflected in the accompanying consolidated financial statements. The matter has settled in 2017 with the Company's portion being $75,000 plus the related legal fees. Legal fees are still being determined.

Arbitration of Employment Claim. A former employee has claimed that the Company owes up to $1,800 under an Executive Severance and Non-Compete agreement (the "Agreement") due to a change of control and termination of employment without cause. The Agreement requires that any disputes be submitted to binding arbitration and a request for arbitration was submitted by the parties in March 2016. Management does not believe there is any merit to the claim of termination without cause or that a change of control occurred. A date has not yet been established for the arbitration proceedings. The ultimate outcome of this arbitration cannot presently be determined. Accordingly, adjustments, if any, that might result from the resolution of this matter have not been reflected in the accompanying consolidated financial statements.

Contingent Ownership Interests. As of December 31, 2016, the Company had recognized a contingent liability associated with uncertain ownership interests of $1,430. This liability arises when the calculations of respective joint ownership interests by operators differs from the Company's calculations. These differences relate to a variety of matters, including allocation of non-consent interests, complex payout calculations for individual wells and groups of wells, along with the timing of reversionary interests. Accordingly, these matters are subject to legal interpretation and the related obligations are presented as a contingent liability in the accompanying consolidated balance sheet as of December 31, 2016. While the Company has classified this entire amount as a current liability, most of these issues are expected to be resolved through arbitration, mediation or litigation; due to the complexity of the issues involved, there can be no assurance that the outcome of these contingencies will be resolved during 2017.

Contingent Gain for Joint Interest Audit Recoveries. The Company has performed joint interest audits of certain drilling, completion and operating costs charged by the Major Operator discussed in Note 15. The results of the audits indicated that $5,269 of costs incurred by the Major Operator in 2011 and 2012 were improperly charged to the accounts for all of the joint interest owners in the wells, including $1,919 related to the Company. During 2015, the Major Operator agreed to issue refunds to the joint interest owners for aggregate charges of $606, aggregate charges for $4,432 were denied, and aggregate charges for $231 are pending further review. The Company has disputed the $4,432 of denied charges, of which its share is approximately $1,600. Since the Company previously paid the full amounts billed by the Major Operator, the dispute will be resolved in accordance with the terms of the joint operating agreements. Except for the refunds issued during 2015, no amounts have been recorded in the accompanying consolidated financial statements for additional recoveries that may result from the joint interest audits.

Anfield Gain Contingency. In 2007, the Company sold all of our uranium assets for cash and stock of the purchaser, Uranium One Inc. ("Uranium One"). The assets sold included a uranium mill in Utah and unpatented uranium claims in Wyoming, Colorado, Arizona and Utah. Pursuant to the asset purchase agreement, the Company was entitled to additional consideration from Uranium One up to $40,000 based on the performance of the mill, achievement of commercial production and royalties, but no additional consideration was ever received from Uranium One. In August 2014, the Company entered into an agreement with Anfield Resources Inc. ("Anfield") whereby if Anfield was successful in acquiring the property from Uranium One, Anfield would be released from the future payment obligations stemming from the 2007 sale to Uranium One. On September 1, 2015, Anfield acquired the property from Uranium One and is now obligated to provide the following consideration to the Company:

- Issuance of $2,500 in Anfield common shares to the Company. The Anfield shares are to be held in escrow and released in tranches over a 36-month period. Pursuant to the agreement, if any of the share issuances result in the Company holding in excess of 20% of the then issued and outstanding shares of Anfield (the "Threshold"), such shares in excess of the Threshold would not be issued at that time, but deferred to the next scheduled share issuance. If, upon the final scheduled share issuance the number of shares to be issued exceeds the Threshold, the value in excess of the Threshold is payable to the Company in cash,
- $2,500 payable in cash upon 18 months of continuous commercial production, and
- $2,500 payable in cash upon 36 months of continuous commercial production.

The first tranche of common shares resulted in the issuance of 7,436,505 shares of Anfield with a market value of $750,000 and such shares were delivered to us in September 2015. The second tranche of shares resulted in the issuance of 3,937,652 additional shares of Anfield with a market value of $750,000, and such shares were delivered to us in September 2016. Since the trading volume in Anfield shares has increased since we took possession, we determined a mark-to-market technique would be the most appropriate method to determine the fair value for Anfield shares. The primary factor in using a mark-to-market valuation in determining the fair value of Anfield shares is justified because of our belief that due to the increased liquidity in the stock, using current market prices for Anfield shares reflects the most accurate fair value calculation. At December 31, 2016, we determined the fair value of the Anfield shares to be approximately $0.9 million. The timing of any future receipt of cash from Anfield is not determinable and there can be no assurance that any cash will ever be received from Anfield or that the shares received from Anfield will ever be liquidated for cash.

11. SHAREHOLDERS' EQUITY

Preferred Stock

The Company's articles of incorporation authorize the issuance of up to 100,000 shares of preferred stock, $0.01 par value. Shares of preferred stock may be issued with such dividend, liquidation, voting and conversion features as may be determined by the Board of Directors without shareholder approval. The Company is authorized to issue 50,000 shares of Series P preferred stock in connection with a shareholder rights plan that expired in 2011. As discussed in Note 6, in February 2016 the Board of Directors approved the designation of 50,000 shares of Series A Convertible Preferred Stock in connection with the disposition of the Company's mining segment.

Warrants

On December 21, 2016, the Company completed a registered direct offering of 1,000,000 shares of common stock at a net price of $1.50 per share. Concurrently, the investors received warrants to purchase 1,000,000 shares of Common Stock of the Company at an exercise price of $2.05 per share, subject to adjustment, for a period of five years from closing. The total net proceeds received by the Company was approximately $1.32 million. The fair value of the warrants upon issuance was $1.24 million, with the remaining $0.08 million being attributed to common stock. The warrants contain a dilutive issuance and other liability provisions which cause the warrants to be accounted for as a liability. Such warrant instruments are initially recorded as a liability and are accounted for at fair value with changes in fair value reported in earnings.

Stock Option Plans *Employee Stock Option Plans.* In December 2001 the Board of Directors adopted, and the Company's shareholders *subsequently* approved, the U.S. Energy Corp. 2001 Incentive Stock Option Plan (the "2001 ISOP"). The 2001 ISOP, as subsequently amended and approved by the Company's shareholders, reserved for issuance 25% of the Company's shares of common stock issued and outstanding at any time. The 2001 ISOP had a term of 10 years which expired in December 2011. Accordingly, no options may be granted under the 2001 ISOP; as of December 31, 2016, options for a total of 360,746 shares are outstanding under the 2001 ISOP and expire on various dates through September 2018.

In June 2012 the Board of Directors adopted, and the shareholders subsequently approved, the U.S. Energy Corp. 2012 Equity and Performance Incentive Plan (the "2012 Equity Plan"). The 2012 Equity Plan, as amended and approved by shareholders in June 2015, reserves for issuance to the Company's employees and Directors a total of 3,200,000 shares of the Company's common stock. The 2012 Equity Plan has a term of 10 years which expires in June 2022. As of December 31, 2016, options for a total of 390,525 shares are outstanding under the 2012 Equity Plan and expire on various dates through January 2025.

Director and Advisory Board Members Option Plan. In June 2008 the Board of Directors adopted, and the shareholders subsequently approved, the 2008 Stock Option Plan for U.S. Energy Corp. Independent Directors and Advisory Board Members (the "2008 Director SOP"). The 2008 Director SOP reserved for issuance 1.0% of the Company's shares of common stock issued and outstanding at any time. The 2008 Director SOP had an original term of 10 years. However, as a result of shareholder approval in June 2015 of an amendment to the 2012 Equity Plan, no additional options may be granted under the 2008 Director SOP. As of December 31, 2016, options for a total of 29,779 shares are outstanding under the 2008 Director SOP and expire on various dates through September 2024.

A summary of the combined activity in the 2001 ISOP, the 2012 Equity Plan, and the 2008 Director SOP for the years ended December 31, 2016, 2015 and 2014 is as follows:

	2016		2015		2014	
	Shares	Price (1)	Shares	Price (1)	Shares	Price (1)
Outstanding, beginning of year	390,525	$ 20.64	2,276,079	$ 3.78	2,646,949	$ 3.56
Granted	-	-	340,711	1.50	60,000	3.77
Forfeited	-	-	-	-	(3,333)	2.08
Expired	-	-	(273,768)	3.86	-	-
Exercised	-	-	-	-	(427,537)	2.46
Outstanding, end of year	390,525	$ 20.64	2,343,022	$ 3.44	2,276,079	$ 3.78
Shares restated after 6 to 1 split	390,525	$ 20.64	390,525	$ 20.64	379,347	$ 22.69
Exercisable, end of year	2,194,022	$ 3.53	2,194,022	$ 3.53	2,031,413	$ 3.92
Shares restated after 6 to 1 split	376,084	$ 20.97	365,693	$ 21.17	338,569	$ 22.75

(1) Represents the weighted average price.

No stock options were exercised during the years ended December 31, 2016 and 2015. During the year ended December 31, 2014, a total of 427,537 stock options were exercised through the payment of nominal cash consideration and the surrender of 257,253 shares valued at $1,106. The aggregate intrinsic value of options exercised in 2014 was $788.

The following table summarizes information for stock options outstanding and for stock options exercisable at December 31, 2016:

Options Outstanding					Options Exercisable	
Number of Shares	Exercise Price Range Low	Exercise Price Range High	Weighted Average	Remaining Contractual Term (years)	Number of Shares	Weighted Average Exercise Price
56,786	$ 9.00	$ 9.00	$ 9.00	8.0	45,675	$ 9.00
49,504	12.48	12.48	12.48	6.5	49,504	12.48
98,396	13.92	17.10	15.01	2.8	98,396	15.01
185,839	22.62	30.24	29.35	1.0	182,509	29.48
390,525	$ 9.00	$ 30.24	$ 20.64	3.2	376,084	$ 20.97

The following table sets forth the number of options available for grant as well as the intrinsic value of the options outstanding and exercisable as of December 31, 2016, 2015 and 2014:

	2016	2015	2014
Shares available for future grants	-	2,108,578	790,000
Shares restated after 6 to 1 split	-	351,430	131,667
Aggregate intrinsic value for options:			
Outstanding	-	-	-
Exercisable	$ -	$ -	$ -

In connection with severance agreements entered into with employees during 2015, an aggregate of 1,617,689 outstanding stock options would have expired upon termination of employment. However, the Company agreed to permit exercise until the original expiration dates specified in the option agreements. Accordingly, the Company determined the fair value of the options at the date of modification and recorded additional compensation expense which amounted to an aggregate of $109.

As of December 31, 2016, no shares are available for future grants under the Company's stock option plans. Based upon the closing price for the Company's common stock of $1.28 per share on December 30, 2016, there was no intrinsic value related to stock options outstanding as of December 31, 2016.

For the years ended December 31, 2016, 2015 and 2014, total stock-based compensation expense associated with stock options, including the modification charge discussed above, was $213, $948 and $318, respectively. As of December 31, 2016, there was $80 of unrecognized expense related to unvested stock options, which will be recognized as stock-based compensation expense through January 2018. The weighted average fair value per share for options granted for the years ended December 31, 2015 and 2014 was $0.88 and $2.27, respectively, and no options were granted in 2016. In estimating the fair value of options, the Company used the Black-Scholes option-pricing model with the following weighted average assumptions:

	2015	2014
Expected lives (in years)	6.0	6.0
Risk-free interest rate	1.77%	2.06%
Expected volatility	63.36%	65.45%
Expected dividend yield	0.00%	0.00%

Restricted Stock Grants. In January 2015, the Board of Directors granted 340,711 shares of restricted stock under the 2012 Equity Plan to four officers of the Company. These shares originally vested annually over a period of three years. However, during 2015 vesting was accelerated for three of the four officers as a condition of severance agreements. Accordingly, 240,711 shares vested in 2015 and the officers elected to surrender an aggregate of 88,637 shares in exchange for the Company's agreement to fund their payroll tax liabilities associated with the fair value of the shares on the dates of vesting.

On September 23, 2016, the Board of Directors granted restricted stock to each member of the Board for 58,500 shares per Board member for an aggregate grant of 351,000 shares. Such shares vest for 50% of the shares on September 23, 2017 and the remaining 50% of the shares vest on September 23, 2018. The closing price of the Company's common stock on the grant date was $1.74, which will result in an aggregate compensation charge of $611 over the two-year vesting period.

The 351,000 shares of restricted common stock were granted pursuant to the Company's 2012 Equity Plan, which provides that each grant constitutes an immediate transfer of ownership that entitles the Board members to voting, dividend and other ownership rights. However, the shares of restricted stock are subject to a substantial risk of forfeiture until vesting occurs. Prior to vesting, the shares are not permitted to be sold or transferred and the directors do not maintain physical custody of the shares.

Employee Stock Ownership Plan

The Board of Directors of the Company adopted the U.S. Energy Corp. 1989 Employee Stock Ownership Plan ("ESOP") in 1989, for the benefit of all the Company's employees. Employees become eligible to participate in the ESOP after one year of service which must consist of at least 1,000 hours worked. Employees become 20% vested after three years of service and increase their vesting by 20% each year thereafter until such time as they are fully vested after seven years of service.

On an annual basis, the Company historically contributed shares of its common stock to the ESOP with an aggregate fair value equal to 10% of compensation for employees that were eligible to participate. Employees were not eligible for ESOP contributions to the extent that their annual taxable compensation exceeded $265 for 2015. All shares of the Company's common stock contributed to the ESOP have been allocated to specific employees and are vested. Total shares held by the ESOP as of September 30, 2016 and December 31, 2015 were 90,112 and 131,518, respectively. In September 2016, the Company's Board of Directors agreed to terminate the ESOP, which is expected to result in a distribution of the remaining shares held by the ESOP to the vested employees during the first quarter of 2017.

For the year ended December 31, 2016, total stock-based compensation expense related to the ESOP was $23. No expense related to the ESOP has been recorded since June 30, 2016 since the Company's Board of Directors has not determined if a discretionary contribution will be made for 2016. On July 7, 2016, the Board of Directors elected to issue 68,128 shares of the Company's common stock with a fair value of $2.49 per share to settle this obligation.

12. INCOME TAXES

The Company incurred a net loss for each of the years ended December 31, 2016, 2015 and 2014, and the Company has recorded valuation allowances for its net deferred tax assets for each of those years. Accordingly, the Company has not recognized a benefit for income taxes in the accompanying financial statements. Income tax benefit using the Company's effective income tax rate differs from the U.S. Federal Statutory income tax rate due to the following:

	2016	2015	2014
Income tax benefit at federal statutory rate	$ 4,801	$ 31,585	$ 711
State income tax benefit, net of federal impact	292	1,440	34
Incentive stock options and restricted stock not deductible for tax purposes	-	(269)	(79)
Percentage depletion carryover	19	-	129
Other, net	534	171	(183)
Increase in valuation allowance	(5,646)	(32,927)	(612)
Income tax benefit (expense)	$ -	$ -	$ -

The components of deferred tax assets and liabilities as of December 31, 2016 and 2015 are as follows:

	2016	2015
Deferred tax assets:		
Net operating loss carryover	$ 26,739	$ 19,947
Property and equipment	14,575	15,645
Percentage depletion and contribution carryovers	2,512	2,433
Alternative minimum tax credit carryover	706	706
Equity method investment and other	547	630
Deferred compensation liability	12	262
Asset retirement obligations	377	442
Stock-based compensation	(44)	302
Total deferred tax assets	45,424	40,367
Deferred tax liabilities:		
Property and equipment	-	-
Oil price risk derivatives	-	(538)
Other	(4)	(4)
Total deferred tax liabilities	(4)	(542)
Net deferred tax assets	45,420	39,825
Less valuation allowance	(45,420)	(39,825)
Net deferred tax asset	$ -	$ -

The Company has net operating loss carryovers as of December 31, 2016 of approximately $74,715 for federal income tax purposes. The net operating loss carryovers may be carried back two years and forward twenty years from the year the net operating loss was generated. The net operating losses may be used to offset future taxable income and expire in varying amounts through 2035. In addition, the Company has alternative minimum tax credit carry-forwards of approximately $700 which are available to offset future federal income taxes over an indefinite period.

The statute of limitations is closed for the tax years through 2010. The Company recognizes, measures, and discloses uncertain tax positions whereby tax positions must meet a “more-likely-than-not” threshold to be recognized. During the years ended December 31, 2016, 2015 and 2014, no adjustments were recognized for uncertain tax positions.

13. EARNINGS (LOSS) PER SHARE

Basic earnings (loss) per share is computed based on the weighted average number of common shares outstanding. The calculation of diluted earnings (loss) per share adds dilutive stock options computed using the treasury stock method as follows:

	2016	2015	2014
Basic weighted average common shares outstanding	4,768,013	4,677,500	4,638,833
Plus dilutive stock options using treasury stock method	-	-	44,334
Diluted weighted average common shares outstanding	4,768,013	4,677,500	4,683,167

For the years ended December 31, 2016, 2015 and 2014, common stock equivalents excluded from the calculation of weighted average shares because they were antidilutive are as follows:

	2016	2015	2014
Stock options	398,360	390,504	225,866
Unvested shares of restricted common stock	24,832	16,667	-
Total	423,192	407,171	225,866

14. SIGNIFICANT CONCENTRATIONS

The Company has exposure to credit risk in the event of nonpayment by the joint interest operators of the Company's oil and gas properties. During the years ended December 31, 2016, 2015 and 2014, three joint interest operators accounted for the following percentages of the Company's oil and gas sales:

Operator	2016	2015	2014
A	16%	20%	38%
B	32%	35%	28%
C	29%	25%	20%

Approximately 22% of the Company's proved developed oil and gas reserve quantities are associated with wells that are operated by operator B (the "Major Operator") as shown in the table above. As of December 31, 2016, the Company had a liability to the Major Operator of $2,710 for accrued operating expenses and overpayments of net revenues when the Major Operator failed to recognize that the Company's ownership interest reverted after payout was achieved for certain wells during 2014 and 2015. Beginning in the second quarter of 2015, the Major Operator began withholding the Company's net revenues from all wells that it operates for the Company and management expects the Major Operator will continue to withhold the Company's net revenues until this liability is paid in full. Based on the oil and gas prices and costs used in the Company's reserve report as of December 31, 2016, this liability is expected to be settled in full by the first quarter of 2017, but under higher pricing scenarios it is possible that the entire liability could be repaid earlier. Accordingly, the aggregate balance of $2,710 is presented as a current liability in the accompanying consolidated balance sheet as of December 31, 2016.

Substantially all of the Company's cash and equivalents are in accounts with a single financial institution and the balances typically exceed federally insured limits. The Company has not experienced any losses in such accounts.

During the years ended December 31, 2015 and 2014 the Company operated in two business segments, the oil and gas industry and the mining industry. As discussed in Note 6, in February 2016 the Company disposed of its mining operations and, accordingly, the mining operations and assets are presented under discontinued operations in the accompanying financial statements.

15. FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In determining fair value, the Company uses various methods including market, income and cost approaches. Based on these approaches, the Company often utilizes certain assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable inputs. The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Based on the observability of the inputs used in the valuation techniques the Company is required to provide the following information according to the fair value hierarchy. The fair value hierarchy ranks the quality and reliability of the information used to determine fair values. Financial assets and liabilities carried at fair value will be classified and disclosed in one of the following three categories:

Level 1 - Quoted prices for identical assets and liabilities traded in active exchange markets, such as the New York Stock Exchange.

Level 2 - Observable inputs other than Level 1 including quoted prices for similar assets or liabilities, quoted prices in less active markets, or other observable inputs that can be corroborated by observable market data. Level 2 also includes derivative contracts whose value is determined using a pricing model with observable market inputs or can be derived principally from or corroborated by observable market data.

Level 3 - Unobservable inputs supported by little or no market activity for financial instruments whose value is determined using pricing models, discounted cash flow methodologies, or similar techniques, as well as instruments for which the determination of fair value requires significant management judgment or estimation; also includes observable inputs for nonbinding single dealer quotes not corroborated by observable market data.

The Company has processes and controls in place to attempt to ensure that fair value is reasonably estimated. The Company performs due diligence procedures over third-party pricing service providers in order to support their use in the valuation process. Where market information is not available to support internal valuations, independent reviews of the valuations are performed and any material exposures are evaluated through a management review process.

While the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different estimate of fair value at the reporting date. The following is a description of the valuation methodologies used for complex financial instruments measured at fair value :

Oil Price Risk Derivative Valuation Methodologies

The Company determines its estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, the credit rating of the counterparty and the Company’s own credit rating. In consideration of counterparty credit risk, the Company assessed the likelihood that the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. There were no derivative contracts in place at December 31, 2016. The crude oil derivative markets are highly active. Although the Company’s derivative instruments are valued using indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Warrant Valuation Methodologies

The warrants contain a dilutive issuance and other liability provisions which cause the warrants to be accounted for as a liability. Such warrant instruments are initially recorded and valued as a level 3 liability and are accounted for at fair value with changes in fair value reported in earnings.

The Company estimated the value of the warrants issued with the Securities Purchase Agreement on December 21, 2016 to be $1,240,000, or $1.24 per warrant, using the Monte Carlo model with the following assumptions: a term expiring June 21, 2022, exercise price of $2.05, volatility rate of 90%, and a risk-free interest rate of 2.12%. The Company remeasured the warrants as of December 31, 2016, using the same Monte Carlo model, using the following assumptions: a term expiring June 21, 2022, exercise price of $2.05, stock price of $1.28, average volatility rate of 90%, and a risk-free interest rate of 2.01%. As of December 31, 2016, the fair value of the warrants was $1,030,000, or $1.03 per warrant, and was recorded as a liability on the accompanying consolidated balance sheets. An increase in any of the variables would cause an increase in the fair value of the warrants. Likewise, a decrease in any variable would cause a decrease in the value of the warrants.

Marketable Equity Securities Valuation Methodologies

The fair value of available for sale securities is based on quoted market prices obtained from independent pricing services. Accordingly, the Company has classified these instruments as Level 1.

Executive Retirement Liability Valuation Methodologies

The executive retirement program is a standalone liability for which there is no available market price, principal market, or market participants. The Company records the estimated fair value of the long-term liability for estimated future payments under the executive retirement program based on the discounted value of estimated future payments associated with each individual in the program. The inputs available for this estimate are unobservable and are therefore classified as Level 3 inputs.

Other Financial Instruments

The carrying amount of cash and equivalents, oil and gas sales receivable, other current assets, accounts payable and accrued expenses approximate fair value because of the short-term nature of those instruments. The recorded amounts for the Senior Secured Revolving Credit Facility discussed in Note 7 approximates the fair market value due to the variable nature of the interest rates, and the fact that market interest rates have remained substantially the same since the latest amendment to the credit facility.

Recurring Fair Value Measurements

Recurring measurements of the fair value of assets and liabilities as of December 31, 2016 and 2015 are as follows:

	December 31, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Marketable equity securitites:								
Sutter Gold Mining Company (1)	$ -	$ 16	$ -	$ 16	$ -	$ 13	$ -	$ 13
Anfield Resources, Inc. (2)	930	-	-	930	-	-	238	238
Crude oil price risk derivatives	-	-	-	-	-	1,634	-	1,634
Total	$ 930	$ 16	$ -	$ 946	$ 25	$ 1,647	$ 238	$ 1,885
Outstanding warrant liability	-	-	1,030	1,030	-	-	-	-
Executive retirement liability	-	-	-	-	-	-	584	584
Total	$ -	$ -	$ 1,030	$ 1,030	$ -	$ -	$ 584	$ 584

(1) Due to a less active market for this investment, during the fourth quarter of 2015 the Company transferred this investment from Level 1 to Level 2 of the fair value hierarchy.

(2) Because the trading volume of Anfield shares have increased since we took possession, we determined a mark-to-market technique would be most appropriate to determine the fair value for Anfield shares. Previously, the Company used alternative methods to determine fair value upon receipt of the shares in September 2015, which requires classification under Level 3 of the fair value hierarchy. The Company has reclassified the Anfield shares under Level 1 of the fair value hierarchy.

The following table presents a reconciliation of changes in assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2016 and 2015:

	Assets				Liabilities			
	Marketable Securities			Crude Oil	Crude Oil	Executive		
	Sutter (Level 1)	Sutter (Level 2)	Anfield (Level 1)	Derivatives (Level 2)	Derivatives (Level 2)	Retirement (Level 3)	Warrants (Level 3)	Net
Fair value, December 31, 2014	25	-	-	-	-	(1,309)	-	(1,284)
Total net losses included in:							-	
Other comprehensive loss	(12)	-	-	-	-	-	-	(12)
Fair value adjustments included in net loss:								
Net realized losses on oil price risk derivatives	-	-	-	(35)	(40)	-	-	(75)
Net unrealized gains on oil price risk derivatives	-	-	-	1,634	-	-	-	1,634
Retirement expense	-	-	-	-	-	(45)	-	(45)
Transfer from Level 1 to Level 2	(13)	13	-	-	-	-	-	-
Acquisition of investment	-		238	-	-	-	-	238
Discount negotiated on settlement	-	-	-	-	-	77	-	77
Offset of derivative assets and liabilities	-	-	-	(40)	40	-	-	-
Cash settlements paid	-	-	-	75	-	694	-	769
Fair value, December 31, 2015	$ -	$ 13	$ 238	$ 1,634	$ -	$ (583)		$ 1,302
Acquisition of investment			750					750
Issuance of warrants							1,240	1,240
Total net losses included in:								
Other comprehensive loss	-	3	-	--	-	-		3
Fair value adjustments included in net loss:								
Net realized losses on oil price risk derivatives	-	-	-	-	-	-		-
Net unrealized gains on oil price risk derivatives	-	-	-	-	-	-		-
Net unrealized gain on warrant valuation							(210)	(210)
Net unrealized loss on Anfield Shares			(58)					(58)
Retirement expense	-	-	-	-	-	-		-
Transfer from Level 1 to Level 2	-	-	-	-	-	-	-	-
Discount negotiated on settlement	-	-	-	-	-	-		-
Offset of derivative assets and liabilities	-	-	-	(194)	-	-		(194)
Cash settlements paid	-	-	-	(1,440)	-	583		(857)
Fair value, December 31, 2016	$ -	$ 16	$ 930	$ -	$ -	$ -	1,030	$ 1,976

16. UNAUDITED SUPPLEMENTAL OIL AND GAS INFORMATION

Oil and Gas Reserves (Unaudited)

Proved reserves are estimated quantities of oil, NGLs and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Oil and gas prices used are the average price during the 12-month period prior to the effective date of the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements. Proved developed reserves are reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and gas reserve quantities at December 31, 2016, 2015 and 2014 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Jane E. Trusty for 2016 and 2015 and by Cawley, Gillespie & Associates, Inc. for 2014. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission. All of the Company's estimated proved reserves are located in the United States.

The Company's estimated quantities of proved oil and gas reserves and changes in net proved reserves are summarized below for the years ended December 31, 2016, 2015 and 2014:

	2016		2015		2014	
	Oil (bbls)	Gas (mcfe) [1]	Oil (bbls)	Gas (mcfe) [1]	Oil (bbls)	Gas (mcfe) [1]
Total proved reserves:						
Reserve quantities, beginning of year	1,615,180	2,477,930	4,119,736	3,211,245	3,459,713	2,371,908
Revisions of previous estimates	(795,459)	(584,494)	(2,377,364)	(206,912)	(262,570)	802,241
Discoveries and extensions	23,841	20,336	94,458	27,102	1,583,292	1,006,659
Sale of minerals in place	(53,853)	(57,258)	-	-	(330,871)	(156,482)
Production	(132,429)	(477,351)	(221,650)	(553,505)	(329,828)	(813,081)
Reserve quantities, end of year	657,280	1,379,163	1,615,180	2,477,930	4,119,736	3,211,245
Proved developed reserves, end of year	657,280	1,379,163	1,248,750	2,068,190	1,754,668	1,892,446

(1) Mcf equivalents (Mcfe) consist of natural gas reserves in mcf plus NGLs converted to mcf using a factor of 6 mcf for each barrel of NGL.

Standardized Measure (Unaudited)

The Company computes a standardized measure of future net cash flows and changes therein relating to estimated proved reserves in accordance with authoritative accounting guidance. The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value amount. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process.

Future cash inflows and production and development costs are determined by applying prices and costs, including transportation, quality, and basis differentials, to the year-end estimated future reserve quantities. The following prices as adjusted for transportation, quality, and basis differentials were used in the calculation of the standardized measure:

	2016	2015	2014
Oil per Bbl	$ 42.75	$ 43.54	$ 85.63
Gas per Mcfe [1]	$ 2.48	$ 3.36	$ 8.84

(1) Consists of the weighted average price for natural gas in mcf plus NGL's converted to mcf using a factor of 6 mcf for each barrel of NGL.

Future operating costs are determined based on estimates of expenditures to be incurred in developing and producing the proved reserves in place at the end of the period using year-end costs and assuming continuation of existing economic conditions. Estimated future income taxes are computed using the current statutory income tax rates, including consideration for estimated future statutory depletion. The resulting future net cash flows are reduced to present value amounts by applying a 10 percent annual discount factor.

The standardized measure of discounted future net cash flows relating to the Company's proved oil and gas reserves is as follows as of December 31, 2016, 2015 and 2014:

	2016	2015	2014
Future cash inflows	$ 27,769	$ 78,646	$ 381,156
Future cash outflows:			
Production costs	(18,814)	(44,685)	(149,450)
Development costs	-	(8,050)	(70,770)
Income taxes	-	-	(12,719)
Future net cash flows	8,955	25,911	148,217
10% annual discount factor	(2,208)	(8,143)	(66,328)
Standardized measure of discounted future net cash flows	$ 6,747	$ 17,768	$ 81,889

Changes in Standardized Measure (Unaudited)

The changes in the standardized measure of future net cash flows relating to proved oil and gas reserves for the years ended December 31, 2016, 2015 and 2014 are as follows:

	2016	2015	2014
Standardized measure, beginning of year	$ 17,768	$ 81,889	$ 104,853
Sales of oil and gas, net of production costs	(3,102)	(2,944)	(21,741)
Net changes in prices and production costs	(9,248)	(96,586)	(17,376)
Changes in estimated future development costs	6,590	51,998	(1,869)
Extensions and discoveries	167	2,260	14,706
Sale of minerals in place	(78)	-	(13,339)
Revisions in previous quantity estimates	(6,791)	(27,693)	(4,815)
Previously estimated development costs incurred	-	-	7,175
Net changes in income taxes	-	3,306	6,924
Accretion of discount	1,777	8,189	10,090
Changes in timing and other	(336)	(2,651)	(2,719)
Standardized measure, end of year	$ 6,747	$ 17,768	$ 81,889

17. QUARTERLY FINANCIAL DATA (Unaudited)

The Company's quarterly financial information for the two-year period ended December 31, 2016 is as follows:

	Year Ended December 31, 2015				Year Ended December 31, 2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil and gas sales	$ 2,679	$ 3,285	$ 2,622	$ 1,710	$ 1,066	$ 1,996	$ 1,867	$ 817
Operating expenses:								
Impairment of oil and gas properties	(19,240)	(3,208)	(21,446)	(13,782)	(6,957)	(2,611)	-	-
Other [1]	(6,174)	(5,266)	(5,534)	(4,710)	(2,561)	(3,061)	(2,761)	276
Operating income (loss) [1]	$ (22,735)	$ (5,189)	$ (24,358)	$ (16,782)	$ (8,452)	$ (3,676)	$ (894)	$ 1,093
Income (loss) from continuing operations [1]	$ (22,919)	$ (5,542)	$ (22,785)	$ (16,038)	$ (8,275)	$ (4,206)	$ (265)	$ 1,074
Discontinued operations	(784)	(738)	(866)	(23,224)	(2,327)	(10)	-	(111)
Net income (loss)	$ (23,703)	$ (6,280)	$ (23,651)	$ (39,262)	$ (10,602)	$ (4,216)	$ (265)	$ 963
Income (loss) per share - basic [1][2]:								
Continuing operations	$ (4.90)	$ (1.19)	$ (4.87)	$ (3.42)	$ (1.76)	$ (0.89)	$ (0.06)	$ 0.23
Discontinued operations	(0.17)	(0.16)	(0.19)	(4.96)	(0.49)	(0.00)	-	-
Total	$ (5.07)	$ (1.35)	$ (5.06)	$ (8.38)	$ (2.25)	$ (0.89)	$ (0.06)	$ 0.23
Income (loss) per share - diluted [1][2]:								
Continuing operations	$ (4.90)	$ (1.19)	$ (4.87)	$ (3.42)	$ (1.76)	$ (0.89)	$ (0.06)	$ 0.23
Discontinued operations	(0.17)	(0.16)	(0.19)	(4.96)	(0.49)	(0.00)	-	-
Total	$ (5.07)	$ (1.35)	$ (5.06)	$ (8.38)	$ (2.25)	$ (0.89)	$ (0.06)	$ 0.23
Weighted average shares outstanding:								
Basic	4,674,667	4,674,667	4,675,167	4,685,167	4,705,500	4,705,000	4,768,000	4,768,013
Diluted [1]	4,674,666	4,674,667	4,675,167	4,685,167	4,705,500	4,705,000	4,768,000	4,768,013

(1) Amounts have been restated from amounts reported in previous reports to retroactively present the impact of Discontinued Operations as discuss further in Note 6.

(2) Earnings per share amounts may not sum due to rounding.

The Company's quarterly reserve reports are prepared based on a trailing 12-month average for benchmark oil and gas prices. The weighted average oil price used to prepare reserve estimates and to calculate the Full Cost Ceiling limitation for the first quarter of 2017 is expected to increase. Assuming other variables remain substantially unchanged, the Company does not expect to record an impairment charge during the first quarter of 2017.

As discussed in Note 7, as of December 31, 2016, the Company and Energy One were not in compliance with any of the financial covenants under their credit facilities and the lender has not provided a limited waiver for the Company's noncompliance.

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

None

PART III

In the event a definitive proxy statement containing the information being incorporated by reference into this Part III is not filed within 120 days of December 31, 2016, we will file such information under cover of a Form 10-K/A.

Item 10 – Directors, Executive Officers and Corporate Governance

The information required by Item 10 with respect to directors and certain executive officers is incorporated herein by reference to our Proxy Statement for the Meeting of Shareholders, under the captions “Proposal 1: Election of Directors,” “Section 16(a) Beneficial Ownership Reporting Compliance,” and “Business Experience of Directors and Officers.” The other information required by Item 10 is also incorporated by reference herein to such Proxy Statement.

The Company has adopted a Code of Ethics. A copy of the Code of Ethics will be provided to any person without charge upon written request addressed to David A. Veltri, Chief Executive Officer, 4643 S. Ulster Street, Suite 970, Denver, Colorado 80237.

Item 11 - Executive Compensation

The information required by Item 11 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders, under the captions “Executive Compensation” and “Non-Employee Director Compensation.”

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

The information required by Item 12 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders, under the caption “Principal Holders of Voting Securities and Ownership by Officers and Directors.”

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

The information required by Item 13 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders, under the caption “Certain Relationships and Related Transactions.”

Item 14 - Principal Accounting Fees and Services

The information required by Item 14 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders, under the caption “Principal Accountant Fees and Services.”

PART IV

Item 15 – Exhibits and Financial Statement Schedules

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules:

The following financial statements are filed in Item 8 of this report:

Report of Independent Registered Public Accounting Firm	57
Financial Statements	
Consolidated Balance Sheets as of December 31, 2016 and 2015	58
Consolidated Statements of Operations and Comprehensive Loss for the Years Ended December 31, 2016, 2015 and 2014	59
Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2016, 2015 and 2014	60
Consolidated Statements of Cash Flows for the Years Ended December 31, 2016, 2015 and 2014	61
Notes to Consolidated Financial Statements	63

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statement and Notes thereto.

(b) Exhibits . The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

2.1**	Mt. Emmons Mining Company Acquisition Agreement (incorporated by reference from Exhibit 2.1 to the Current Report on Form 8-K filed February 12, 2016)
3.1**	Restated Articles of Incorporation (incorporated by reference from Exhibit 4.1 to the Company's Registration Statement on Form S-3, [333-162607] filed October 21, 2009)
3.2**	Restated Bylaws, dated as of April 3, 2014 (incorporated by reference from Exhibit 3.2 to the Company's Report on Form 8-K filed April 7, 2014)
3.3**	Certificate of Designation for Series A Convertible Preferred Stock (incorporated by reference from Exhibit 3.1 to the Current Report on Form 8-K filed February 12, 2016)
3.4**	Articles of Amendment to Restated Articles of Incorporation (incorporated by reference from Exhibit 3.1 to the Company's Form 8-K filed June 21, 2016)
4.1**	Common Stock Purchase Warrant (incorporated by reference from Exhibit 4.1 to the Company's Report on Form 8-K filed December 22, 2016)
10.1(a)**	BNP Paribas– Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed August 2, 2010)
10.1(b)**	Wells Fargo Bank, National Association – Second Amendment to Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed July 25, 2013)
10.1(c)**	Wells Fargo Bank, National Association – Third Amendment to Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed July 16, 2015)
10.1(d)**	Wells Fargo Bank, National Association – Fourth Amendment to Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 10-Q filed August 15, 2016)
10.1(e)**	BNP Paribas – Mortgage Agreement (incorporated by reference from Exhibit 10.2 to the Company's Form 8-K filed August 2, 2010)
10.1(f)**	Wells Fargo Bank, National Association – Guaranty (incorporated by reference from Exhibit 10.3 to the Company's Form 8-K filed August 2, 2010)
10.2**†	USE 2001 Officers' Stock Compensation Plan (incorporated by reference from Exhibit 4.21 to the Company's Annual Report on Form 10-K filed September 13, 2002)
10.3**†	2001 Incentive Stock Option Plan (amended in 2003) (incorporated by reference from Exhibit 4.2 to the Company's Annual Report on Form 10-K filed April 15, 2005)
10.4**	2008 Stock Option Plan for Independent Directors and Advisory Board Members (incorporated by reference from Exhibit 4.3 to the Company's Annual Report on Form 10-K filed March 13, 2009)
10.5**†	U.S. Energy Corp. Employee Stock Ownership Plan (incorporated by reference from Exhibit 4.1 to the Company's S-8 filed April 13, 2012)

10.6**†	Amended and Restated 2012 Equity and Performance Incentive Plan (incorporated by reference from Appendix A to the Company's Proxy Statement on Form DEF14A filed April 28, 2015)
10.6.1**	Form of Grant to the 2012 Equity and Performance Incentive Plan (incorporated by reference from Exhibit 10.5.1 to the Form 10-K filed March 18, 2013)
10.7*	Amendment Assignment and Assumption Agreement (Anfield Resources and Uranium One) dated as of August 14, 2014
10.8(a)**†	Executive Employment Agreement – Keith G. Larsen (effective 4-20-12) (incorporated by reference from Exhibit 10.1 to the Form 8-K filed January 17, 2012)
10.8(b)** †	Executive Employment Agreement – David Veltri (effective 10-23-15) (incorporated by reference from Exhibit 10.2 to the Form 10-Q filed August 15, 2016)
10.8(c)**†	Agreement and Mutual Release of All Claims – Keith G. Larsen (effective 9-25-15) (incorporated by reference from Exhibit 10.8(b) to the Form 10-K/A filed April 29, 2016)
10.8(d)**†	Agreement and Mutual Release of All Claims – Steven D. Richmond (effective 12-31-15) (incorporated by reference from Exhibit 10.8(c) to the Form 10-K/A filed April 29, 2016)
10.8(e)**†	Agreement and Mutual Release of All Claims – Bryon G. Mowry (effective 12-31-15) (incorporated by reference from Exhibit 10.8(d) to the Form 10-K/A filed April 29, 2016)
10.8(f)**†	Form of Executive Severance and Non-Compete Agreement (incorporated by reference from Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed on May 10, 2013)
10.9**	Agreement for Purchase of Leasehold Interests in McKenzie and Williams Counties, North Dakota (Brigham Oil & Gas, L.P.) (incorporated by reference from Exhibit 10.6 to the Company's Annual Report on Form 10-K filed March14, 2012)
10.10(a)**	Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota (Geo Resources, Inc.) (incorporated by reference from Exhibit 10.7(a) to the Company's Annual Report on Form 10-K filed March14, 2012)
10.10(b)**	Amendments (5) to Agreement for Purchase of Leasehold Interest in McKenzie County, North Dakota (Geo Resources, Inc.) (incorporated by reference from Exhibit 10.7(b) to the Company's Annual Report on Form 10-K filed March14, 2012)
10.11(a)**	Participation Agreement between Energy One, LLC and Contango/Crimson effective February18, 2011 for the Leona River Project (incorporated by reference from Exhibit 10.10(a) to the Company's Annual Report on Form 10-K filed March 12, 2014)
10.11(b)**	Participation Agreement between Energy One, LLC and Contango/Crimson effective April 1, 2011 for the Booth/Tortuga Project (incorporated by reference from Exhibit 10.10(b) to the Company's Annual Report on Form 10-K filed March 12, 2014)
10.12**	Series A Convertible Preferred Stock Purchase Agreement (incorporated by reference from Exhibit 10.1 to the Current Report on Form 8-K filed February 12, 2016)
10.13**	Investor Rights Agreement (incorporated by reference from Exhibit 10.2 to the Current Report on Form 8-K filed February 12, 2016)
10.14**	Securities Purchase Agreement dated as of December 16, 2016 (incorporated by reference from Exhibit 10.1 to the Company's Report on Form 8-K filed December 22, 2016)
14.0**	Code of Ethics (incorporated by reference from Exhibit 14 to the Company's Annual Report on Form 10-K filed March 30, 2004)
21.1**	Subsidiaries of Registrant (incorporated by reference from Exhibit 21.1 to the Company's Annual Report on Form 10-K filed on March 12, 2014)
23.1*	Consent of Independent Registered Accounting Firm (Hein & Associates LLP)
23.2*	Consent of Reserve Engineer (Jane E. Trusty, PE)
23.3*	Consent of Reserve Engineer (Cawley, Gillespie & Associates, Inc.)
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
31.2*	Certification of principal financial officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1*	Certification under Rule 13a-14(b) of Chief Executive Officer and principal financial officer
99.1*	Reserve Report (Jane E. Trusty, PE)
99.2**	Reserve Report (Cawley, Gillespie & Associates, Inc.) (incorporated by reference from Exhibit 99.1 to the Form 10-K filed March 12, 2014)
101.INS	XBRL Instance Document

101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.DEF	XBRL Definition Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document

* Filed herewith.
** Previously filed.
† Exhibit constitutes a management contract or compensatory plan or agreement.

SIGNATURES

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

		U.S. ENERGY CORP.
Date: April 17, 2017	By:	/s/ David A. Veltri
		DAVID A. VELTRI, Chief Executive Officer

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

Date: April 17, 2017	By:	/s/ David A. Veltri
		DAVID A. VELTRI, Director, President and CEO (Principal Executive and Financial Officer)
Date: April 17, 2017	By:	/s/ Thomas R. Bandy
		THOMAS R. BANDY, Director
Date: April 17, 2017	By:	/s/ Jerry W. Danni
		JERRY W. DANNI, Director
Date: April 17, 2017	By:	/s/ James B. Fraser
		JAMES B. FRASER, Director
Date: April 17, 2017	By:	/s/ Leo A. Heath
		LEO A. HEATH, Director

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-204350 and 333-215887) and the Registration Statements on Form S-8 (No. 333-108979, 333-166638, 333-180735, and 333-183911) of U.S. Energy Corp. of our report dated April 17, 2017, relating to our audits of the consolidated financial statements, included in the Annual Report on Form 10-K of U.S. Energy Corp. for the years ended December 31, 2016, 2015 and 2014.

Our report dated April 17, 2017 contains an explanatory paragraph that states that the Company has a working capital deficit, an accumulated deficit, has incurred recurring losses from operations, and is in default of its loan covenants as of and for the year ended December 31, 2016, which raises substantial doubt about the Company's ability to continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ Hein & Associates LLP

Denver, Colorado
April 17, 2017

Exhibit 23.3

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS

13640 BRIARWICK DR., SUITE100 AUSTIN, TEXAS 78729-1107 512-249-7000	306 WEST SEVENTH STREET, SUITE 302 FORT WORTH, TEXAS 76102-4987 817- 336-2461 www.cgaus.com	1000 LOUISIANA STREET, SUITE 625 HOUSTON, TEXAS 77002-5008 713-651-9944

CONSENT OF CAWLEY, GILLESPIE & ASSOCIATES, INC.

We hereby consent to the inclusion in this Annual Report on Form 10-K prepared by U.S. Energy Corp. (the "Company") for the year ending December 31, 2016, and to the incorporation by reference for the years ending December 31, 2014, of our reports relating to certain estimated quantities of the Company's proved reserves of oil and gas, future net income and discounted future net income, effective December 31, 2014 and 2013. We further consent to references to our firm under Item 2- Properties under the heading "Oil and gas" and Item 8, Note 17 of the Notes to Consolidated Financial Statements under the caption "Oil and Gas Reserves (Unaudited)".

We also consent to the incorporation by reference of information from our Report into the Company's Registration Statements on Form S-3 (No. 333-204350 and 333-215887), and the Registration Statements on Form S-8 (No. 333-108979, 333-166638, 333-180735, and 333-183911).

Very truly yours,

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/s/ W. Todd Brooker
W. Todd Brooker, P.E.
Senior Vice President
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

Austin, Texas
April 17, 2017

X ____

Exhibit 31.1

CERTIFICATION PURSUANT TO RULES 13a-14(a) AND 15d-14(a) UNDER THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David A. Veltri, certify that:

1. I have reviewed this Annual Report on Form 10-K of U.S. Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant, as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: April 17, 2017

By: /s/ David A. Veltri

David A. Veltri
President, Chief Executive Officer and principal financial officer

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of U.S. Energy Corp. (the "Company") for the period ending December 31, 2016 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: April 17, 2017

By: /s/ David A. Veltri
David A. Veltri
President, Chief Executive Officer and principal financial officer

Exhibit 99.1

U. S. Energy Corp.

Estimate of Future Reserves and Net Income Attributable to Certain Leasehold Interests Located in North Dakota, Texas, and Louisiana AS OF December 31, 2016

Prepared for:

Mr. David Veltri US Energy Corp
4643 S. Ulster St. Suite 970
Denver, CO 80237

March 16, 2017

Jane E. Trusty, PE 4608 Thuesen Rd
Needville, TX 77461
713-412-9455
trustyj@consolidated.net

(This report has been prepared at the request of US Energy Corp. The information contained in this report is privileged and confidential information intended for the use of US Energy Corp. The distribution and use of this report inconsistent with its stated use is prohibited.)

March 16, 2017

Mr. David Veltri
US Energy Corp.
4643 S. Ulster St.
Suite 970
Denver, CO 80237

Re: Estimate of Future Reserves and Net
Income Attributable to Certain Leasehold Interests For: Energy One LLC Interests
Located in North Dakota, Texas, and Louisiana Dear Mr. Veltri:

Pursuant to your request, enclosed is the report presenting the volume of Oil and Gas Reserves net to Energy One LLC Interests for certain oil and gas properties located in North Dakota, Texas, and Louisiana, and the Future Net Revenue from them as of December 31, 2016.

Please note that this report is based upon the following:

1. Production Data by well, Land and Accounting information supplied by U. S. Energy Corporation (USEnergy).

2. Information obtained from public records, including ND oil and gas, Sonris, Drillinginfo.com and the Railroad Commission of Texas Production Database.

In accordance with your instructions, this report is a valuation of the Proved Reserves net to Energy One. Probable and Possible Reserves, net to Energy One as of December 31, 2016, have not been evaluated.

The oil price used to evaluate the future net revenue was the average of the
12 months prior WTI spot close of 12-31-2016 in accordance with SEC guidelines as shown below.

12 month average Oil Pricing WTI spot
$42.75/Bbl **January 1, 2017 - Thereafter**

The price differentials were based on the prior year history provided by USEnergy using oil revenues and the net volumes from accounting. Most of the North Dakota operators had a $6 deduction, Louisiana production had no deduction, and most of Texas had a $2 deduction from WTI on average.

The gas price used for this report was the 12 month average price for 2016 ending 12-31-16 in accordance with SEC guidelines as shown below.

Henry Hub 12 month average Gas Pricing

$2.48/MMBTU	**January 1, 2017- Thereafter**

The specific gas price adjustment for each operator was calculated from net volumes and net revenue from the gas. The gas price was also adjusted for the specific BTU content of the gas for each well and/or area. In order to account for lease fuel and separation/extraction losses, gas volumes for each operator were also adjusted for gas shrinkage based on the net accounting volumes compared to net production volumes. Shrinkage was averaged by operator.

Expenses from US Energy were reviewed for each operator and compared to LOS data provided by accounting. The expenses were adjusted based on the past 11 months of history supplied by US Energy.

Mr. Veltri please review this report for Energy One's oil and gas reserves and contact me at your convenience so that we may discuss it in detail.

Very truly yours

Jane E. Trusty, PE

Energy One LLC Interests
Reserve Estimate and Determination of Future Net Revenue
As Of December 31, 2016
North Dakota, Texas, and Louisiana

Enclosed are estimates of the Net Proved Reserves and the Future Net Income, attributable from certain producing leasehold interests located in North Dakota, Texas, and Louisiana, as prepared by Jane Trusty, PE. This Reserve Estimate and Determination of Future Net Revenue includes only the Proved Reserves net to Energy One LLC. The net interests owned were provided by U.S. Energy Corp. and were accepted as furnished.

As requested, Probable and/or Possible reserves, if any, have not been evaluated. The effective date for these estimates is December 31, 2016. The economic runs start on 1- 1-2017 and do not include any December volumes. The volumes are summarized as follows:

	Net Reserves		
	Net Liquids MBBLS	**Net Gas MMcf**	**Net Equivalent MBOE**
Proved Developed Producing	657.28	1278.26	870.32
Proved Developed Non-Producing	0.00	100.91	16.82
Proved Undeveloped	0.0	0.0	0.0
Total Proved	657.28	1379.17	887.12

The liquid reserves shown above are comprised of crude oil and condensate, and are expressed in oilfield standard 42-gallon barrels. All gas volumes are sales gas volumes expressed in MCF at standard pressure and temperature for the area. Net Equivalent reserves, expressed in Barrels of Oil Equivalent ("BOE"), are based upon a six-to-one BTU parity between gas and oil.

The estimates of future revenues, future costs, and future cash flows before Federal Income Taxes as of December 31, 2016, are based upon the hydrocarbon volumes calculated above, and are summarized as follows:

Category		Future Total Net Revenue $M		Future Production Costs $M		Future Net Investment $M		Future Net Cash Flow $M Undis		Future Net Cash Flow $M 10%
Proved Developed Producing	$	27,516.93	$	18,747.21	$	0.00	$	8,769.73	$	6,604.72
Proved Developed Non-Producing	$	252.54	$	61.43	$	5.40	$	185.72	$	142.58
Proved Undeveloped	$	0.00	$	0.00	$	0.00	$	0.00	$	0.00
Total Proved	$	27,769.47	$	18,808.63	$	5.40	$	8,955.44	$	6,747.30

Future Total N e t Revenue is revenue net to Energy One's interest after the deduction of royalties, but before any deductions for production-related expenses. Production Costs are based upon current expense levels and include state severance and production taxes, ad valorem taxes, direct field operating expenses, and routine well reconditioning expenses as billed from operators to Energy One LLC.

Future Investments include well recompletion expenses and development well drilling, completion, and equipping costs. No provisions have been made for lease and well equipment salvage values, due to the assumption that any such proceeds will be used to offset plugging liabilities.

To compute Future Cash Flow attributable to Energy One the average WTI spot prices for the 12 month period ending December 31, 2016 were averaged according to the SEC guidelines. The price was not escalated.

Oil Pricing
$42.75/Bbl **January 1, 2017 - Thereafter**

The oil prices were adjusted for each operator and area based on the net revenues and net volumes. The average oil price for the North Dakota properties had a $6 deduction from WTI. All deductions were evaluated by operator from accounting data furnished by USEnergy. The Texas properties had an average deduction of $2 and Louisiana had no deduction.

Gas prices used for this report are the average NYMEX gas price for the 12 months ending December 31, 2016.

Gas Pricing
$2.48/MMBTU **January 1, 2017 - Thereafter**

The gas price differential was calculated from the net gas revenue and volumes, compared to the NYMEX price for that month. Gas production was also adjusted for shrinkage due to lease fuel usage, liquid extraction and normal production processing losses. The net gas volumes from accounting were compared to the net production values from production reporting and the NRI for each well. The Net gas volumes in this report are the Net gas sales after all shrinkage.

Production Costs were not escalated and the cost of Investment Capital used in future drilling, completion and reworking operations were also un-escalated. Furthermore, production costs for each operator were based upon the past 11 months of actual expenses incurred by Energy One as billed by operators. All of the expense data came directly from USEnergy.

Production Costs for Proved Undeveloped Reserves in this report are based upon current charges for analogous production by each operator; these Production Costs were also un-escalated.

No deduction has been made for any indirect costs such as general administration or overhead expenses (above the standard COPAS which is included in the operating expense), loan repayments or depreciation expenses.

Due to the current oil price, for this evaluation no PUDS (Proved Undeveloped locations) that were on the SEC report YE 2015 were considered at this time, and therefore, are not shown. As prices and drilling costs change the List of PUDS will also change, but at this time are not included in the reserve estimate for YE 2016.

The reserve estimates contained in this report have been prepared based upon certain production, and accounting information supplied by the staff of U.S. Energy Corp. In addition to the data supplied by USEnergy, public data sources were used to obtain production and test data for the wells. These properties have not been examined in the field. All forecasts were made in accordance with the accepted engineering estimates of production performance and offset analogy.

Jane Trusty, a State of Texas licensed Professional Engineer (License #60812), the preparer of this report, is an independent Petroleum Engineering consultant to U.S. Energy Corp. and does not own any interest in any of the properties. The fee paid by U. S. Energy Corp. for these services is not contingent upon the results of this report.

The reserves included in this report are estimates only and should not be construed as being exact quantities. All estimates represent best engineering judgment of the data available at the time of preparation. Such volumes may or may not be actually recovered. In addition, these estimates may increase or decrease as result of actual product prices which will effect the economic producing limit of wells and/or future operations and decisions made by the operators and U.S. Energy Corp.