US ENERGY CORP
Form 10-K
March 28, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2017

[ ] **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.)
950 S. Cherry St., Suite 1515, Denver, Colorado	**80246**
(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 [X]

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 [X]

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 [X] 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 [X] 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 [X]

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

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, 2017, was $4,171,464.

The Registrant had 12,440,927 shares of its $0.01 par value common stock outstanding as of March 21, 2018.

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 2018 annual meeting of stockholders to be filed within 120 days after December 31, 2017.

TABLE OF CONTENTS

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, Zavanna and other partners;
- expected working and net revenue interests, and costs of wells, relating to the drilling programs with our partners;
- actual decline rates for producing wells in the Buda, Bakken/Three Forks, Eagle Ford and other formations;
- future cash flows, expenses and borrowings;
- pursuit of potential acquisition opportunities;
- our expected financial position;
- our expected future overhead reductions;
- our ability to become an operator of oil and gas properties;
- our ability to raise additional financing and acquire attractive oil and gas properties; and
- other plans and objectives for future operations.

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

- our ability to obtain sufficient cash flow from operations, borrowing and/or other sources to fully develop our undeveloped acreage positions;
- volatility in oil and gas prices, including further declines in oil prices and/or natural gas prices, which would have a negative impact on operating cash flow and could require further ceiling test write-downs on our oil and gas assets;

- the possibility that the oil and gas industry may be subject to new adverse regulatory or legislative actions (including changes to existing tax rules and regulations and changes in environmental regulation);
- the general risks of exploration and development activities, including the failure to find oil and gas in sufficient commercial quantities to provide a reasonable return on investment;
- future oil and gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;
- the ability to replace oil and gas reserves as they deplete from production;
- environmental risks;
- risks associated with our plan to develop additional operating capabilities, including the potential inability to recruit and retain personnel with the requisite skills and experience and liabilities we could assume or incur as an operator or to acquire operated properties or obtain operatorship of existing properties;
- availability of pipeline capacity and other means of transporting crude oil and gas production, and related midstream infrastructure and services;
- competition in leasing new acreage and for drilling programs with operating companies, resulting in less favorable terms or fewer opportunities being available;
- higher drilling and completion costs related to competition for drilling and completion services and shortages of labor and materials;
- unanticipated weather events resulting in possible delays of drilling and completions and the interruption of anticipated production streams of hydrocarbons, which could impact expenses and revenues; and
- unanticipated down-hole mechanical problems, which could result in higher than expected drilling and completion expenses and/or the loss of the wellbore or a portion thereof.

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

Glossary of Oil and Gas Terms

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

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

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

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

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

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

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

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

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

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

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

Mcf. One thousand cubic feet of natural gas.

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

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

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

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

Oil. Crude oil, condensate or other liquid hydrocarbons.

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

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

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

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

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

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

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

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

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

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 950 S. Cherry Street, Suite 1515, Denver, Colorado 80246, 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 824,115 BOE (82% oil and 18% natural gas) as of December 31, 2017, with a standardized measure value of $9.3 million.
As of March 28, 2018, our oil and gas leases covered 89,842 gross and 4,744 net acres.
126 gross (13.89 net) producing wells as of December 31, 2017 and as of March 28, 2018.

511 BOE per day average net production for 2017.

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, 2017, 2016 and 2015:

	2017	2016	2015
Standardized measure of discounted net cash flows	$9,253	$6,747	$17,768
Plus discounted impact of future income tax expense	-	-	-
PV-10	$9,253	$6,747	$17,768

Additional information about our standardized measure and the changes during each of the last three years is included in Note 16 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 significant oil and gas projects with our key operating partners which constitute the majority of our production and reserves. In addition to the below descriptions, the Company holds interests in non-operated wells with several operators which constitute the remainder of our PV-10.

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

Zavanna, LLC. We have an interest in multiple wells with Zavanna with a working interest of approximately 8.75% and net revenue interests ranging from 6.7% to 7.0%. These properties operated by Zavanna currently comprise approximately 59% of the PV-10 related to our oil and gas reserves.

Texas and Louisiana (Gulf Coast)

Contango Oil and Gas Company (Eagle Ford Shale). We have an interest in multiple wells with Contango who is the operator of the Leona River and Booth Tortuga prospects in which we currently hold a 30% working interest and 22.5% net revenue interest. All of the leases are currently held by production and comprise approximately 8% of the PV-10 related to our oil and gas reserves.

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 and they are all held by production. These properties operated by PetroQuest currently comprise approximately 7% 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, legislative and regulatory initiatives that can materially adversely affect the timing and cost of operations and the demand for crude oil, natural gas, and NGLs*; *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 liabilities 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.

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 (the “CAA”). Applicable to our business and operations, the CAA regulates the emissions, discharges and controls of oil and natural gas production and natural gas processing operations. The CAA 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 CAA 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.

On April 17, 2012, the EPA finalized rules proposed on July 28, 2011 that establish new air emission controls under the CCA for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes NSPS for the oil and natural gas source category to address emissions of sulfur dioxide and 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.

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 disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended ("SDWA"), and analogous state laws. The SDWA's Underground Injection Control Program establishes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities as well as a prohibition against the migration of fluid containing any contaminants into underground sources of drinking water. State programs may have analogous permitting and operational requirements. In response to concerns related to increased seismic activity in the vicinity of injection wells, regulators in some states are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission ("RRC") adopted new oil and gas permit rules in October 2014 for wells used to dispose of saltwater and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position. In addition, any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injury.

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 is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. Over the years, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. For example, the EPA has adopted final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management ("BLM") finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. However, the BLM finalized a rule in December 2017 repealing its March 2015 hydraulic fracturing regulations. The repeal has been challenged in court and the final outcome is uncertain at this time.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA has not proposed to take any action in response to the report's findings, and additional regulation of hydraulic fracturing at the federal level appears unlikely at this time.

While Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process, the prospect of additional federal legislation related to hydraulic fracturing appears remote at this time. At the state level, some states, including Louisiana and Texas, where we have interests, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Moreover, some states and local governments have enacted laws or regulations limiting hydraulic fracturing within their borders or prohibiting the activity altogether. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

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.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA required federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare and Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Governmental permits or authorizations that are subject to the requirements of NEPA are required for exploration and development projects on federal and Indian lands. This process has the potential to delay, limit or increate the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Many of the activities of our third-party operating partners are covered under categorical exclusions which results in a shorter NEPA review process, however, the impact of the NEPA review process on our third-party operating partners is uncertain at this time and could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Climate Change

The EPA has determined that greenhouse gases present an endangerment to public health and the environment and has issued regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources of greenhouse gas emissions (“GHG”). The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from a variety of sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions from completions and workovers from hydraulically fractured oil wells. Also, in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect. Future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, or any other new methane emission standards imposed on the oil and gas sector, could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

Currently, federal legislation related to the reduction of greenhouse gas emissions appears unlikely; however, many states have established greenhouse gas cap and trade programs, and others are considering carbon taxes or initiatives that promote the use of alternative fuels and renewable sources of energy. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for the oil and natural gas we produce, which could in turn have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, it should be noted 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 increased frequency and severity of storms, droughts and floods and other extreme weather events. Such events could disrupt our operations or result in damage to our assets and have an adverse effect on our financial condition and results of operations.

Our third-party operating partners are required to report their GHG under these rules. 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.

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 2017 and 2018, we have continued, and will continue, to maintain $10 million of coverage for environmental impairment liability.

Employees

As of December 31, 2017, we had 3 total and full-time employees and we utilized several consultants on an as needed basis.

Forward Plan

In 2018 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.

Extend the Maturity of Existing Debt. In June 2017, the Company extended the maturity of its Credit Facility to July 30, 2019.

Further strengthen our balance sheet and preserve financial flexibility. In December 2017, the Company closed an exchange agreement by and among the Company, the Company's wholly owned subsidiary Energy One LLC, and APEG Energy II, L.P. pursuant to which, the Company exchanged $4.5 million of the outstanding borrowings under its Credit Facility for 5,819,270 shares of common stock, resulting in an 84% reduction in annual interest payments.

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.

While commodity prices have improved throughout 2017, they have remained volatile over the past three years. 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.

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 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.

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 are presented as discontinued operations for the year ended December 31, 2016.

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 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, 2017, oil prices have ranged from highs over $60 per barrel in mid-2017 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 volatility of comparable magnitude over the same time period. Volatility 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 (Bakken and Three Forks Shales) 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 2017, our realized oil prices in the Williston Basin were approximately $6.78 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 and to affect 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 APEG Energy II, L.P. 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) PDP Coverage Ratio shall not be less than 1.2 to 1.0; and (ii) the Current Ratio to exceed 1.0 to 1.0, each as defined in the Credit Facility. As of December 31, 2017, Energy One was in compliance with all financial covenants.

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.

Our industry partners may elect to engage in drilling activities that we are unwilling or unable to participate in during 2018. 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 holds 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.

Our ability to use net operating loss carryforwards and realized built in losses to offset future taxable income for U.S. federal income tax purposes is subject to limitation.

In general, under Section 382 of the Internal Revenue Code of 1986, as amended, a corporation that undergoes an “ownership change” is subject to limitations on its ability to utilize its pre-change net operating losses (“NOLs”) and realized built in losses (“RBILS”) offset future taxable income. In general, an ownership change occurs if the aggregate stock ownership of certain stockholders (generally 5% stockholders, applying certain look-through rules) increases by more than 50 percentage points over such stockholders’ lowest percentage ownership during the testing period (generally three years).

On December 27, 2017, the Company paid down debt with common stock. This represented a 49.3% ownership change in the company. As a result, the Company’s Net Operating Loss carryforwards will likely be significantly reduced in 2018.

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 fracture stimulation 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 2017, capitalized costs for oil and gas properties did not exceed the ceiling and therefore we recorded no aggregate ceiling test write-downs. 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, 2017, we used a weighted average price applicable to our properties of $51.34 per barrel for oil and $2.98 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, 2017. 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 elected to withhold the net revenues from all of our wells that it operates to recover these overpayments, decreasing cash flows that would otherwise have been available to operate our business.

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, 2017, all of our estimated proved reserves were 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.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), which was passed by the U.S. Congress and signed into law in July 2010, provides for statutory and regulatory requirements for derivative transactions, including crude oil and natural gas derivative transactions. Among other things, the Dodd-Frank Act provides for the creating of position limits for certain derivatives transaction, as well as requiring certain transaction to be cleared on exchanges for which cash collateral will be required. The Dodd-Frank Act requires the Commodities Futures and Trading Commission (the “CFTC”), and the SEC and other regulators to promulgate rules and regulations implementing the Dodd-Frank Act. The CFTC has re-proposed rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on is us uncertain at this time.

It is not possible at this time to predict with certainty the full effect of the Dodd-Frank Act and the CFTC rules on us and the timing of such effects. The Dodd-Frank Act may require us to comply with margin requirements and with certain clearing and trade-execution requirements if we do not satisfy certain specific exceptions. Although we expect to qualify for the end-use exception to the clearing, trade-execution and margin requirement for swaps entered to hedge our commodity risks, the application of the requirements to other market participants, such as swap dealers, may change the cost and availability of our derivatives. Depending on the rules adopted by the CFTC or similar rules that may be adopted by other regulatory bodies, we might in the future be required to provided cash collateral for our commodities derivative transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could therefore reduce our ability to execute transactions to reduce commodity price risk and thus protect cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements on our business will not be known until all of the regulations are implemented. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operation may become more volatile and our cash flows may be less predictable. In addition, the Dodd-Frank Acts was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices.

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, legislative and regulatory initiatives that can materially adversely affect the timing and cost of operations and the demand for crude oil, natural gas, and NGLs.

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 including, but not limited to the following:

23

- 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

The Resource Conservation and Recovery Act ("RCRA") and comparable state statues regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. In the course of our operations, we and others generate petroleum hydrocarbon wastes, produced water and ordinary industrial wastes. While the RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of crude oil and natural gas from regulation as hazardous wastes, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements, we can provide no assurance that this exemption will be preserved in the future. For example, following the filing of a lawsuit by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulation for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the U.S. District Court for the District of Columbia in December 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulation, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. 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 (the "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.

The CAA and comparable state laws regulate emissions of various air pollutants through air emissions, permitting programs and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions at specified sources. For example, under the EPA's New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") regulations, since January 1, 2015, owners and operators of hydraulically fractured natural gas wells (wells drilled principally for the production of natural gas) have been required to use so-called "green completion" technology to recover natural gas that formerly would have been flared or vented. In 2016, the EPA issued additional rules for the oil and gas industry to reduce emissions of methane, VOCs and other compounds. These rules apply to certain sources of air emissions that were constructed, reconstructed, or modified after September 18, 2015. Among other things, the new rules impose green completion requirements on new hydraulically fractured or re-fractured oil wells and leak detection and repair requirements at well sites. We do not expect that the currently applicable NSPS or NESHAP requirements will have a material adverse effect on our business, financial condition or results of operations. However, any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permitting requirements or use specific equipment or technologies to control emissions.

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.

Discharges into Waters

The federal Water Pollution Control Act, or the Clean Water Act (the “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 (the “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 (the “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

Certain scientific studies have found that emissions of carbon dioxide, methane and other “greenhouse gases” are contributing to warming of the Earth’s atmosphere and other climatic changes. Based on these findings, the EPA determined that greenhouse gases present an endangerment to public health and the environment and has issued regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. These regulation include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from a variety of sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis, including greenhouse gas emission from collection and workover from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. Also in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission, and storage activities. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect. Future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The Suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, or any other new methane emission standards imposed on the oil and gas sector, could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. 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.

Currently, federal legislation related to the reduction of greenhouse gas emissions appears unlikely; however, many state have established greenhouse gas cap and trade programs, and others are considering carbon taxes or initiatives that promote the use of alternative fuels and renewable sources of energy. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce, which in turn could have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oi and natural gas activities. Ultimately this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. It should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other extreme weather events. Such weather events could disrupt our operations or result in damages to our assets and have an adverse effect on our financial condition and results of operations.

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, which went into effect in November 2016, could further drive regulation in the United States. However, in June 2017, the United States announced its withdrawal from the Paris Agreement, although the earliest possible effective date of withdrawal is November 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. The United States' adherence to the exit process is uncertain and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. 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.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Over the years, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. For example, the EPA has taken the following actions and issued: guidance under the SDWA for hydraulic fracturing activities involving the use of diesel fuel; final regulations under the federal

CAA governing performance standards, including standards for the capture of volatile organic compounds and methane emissions released during hydraulic fracturing and finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. However, the BLM finalized a rule in December 2017 repealing its March 2015 hydraulic fracturing regulations. The repeal has been challenged in court and the final outcome is uncertain at this time.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA has not proposed to take any action in response to the report’s findings and additional federal regulation of hydraulic fracturing appears unlikely at this time.

While Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process, the prospect of additional federal legislation related to hydraulic fracturing appears remote at this time. At the state level, some states, including Louisiana and Texas, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. There has also been increased public scrutiny of seismic events in areas where hydraulic fracturing of wastewater disposal activities occur. Moreover, some states and local governments have enacted laws or regulations limiting hydraulic fracturing within their borders or prohibiting the activity altogether. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling 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.

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.

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.

Permitting

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.

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 and Chief Financial Officer have experience in dealing with the acquisition 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 or Chief Financial 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 793,000 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.

One of our existing stockholders beneficially owns a significant portion of our common stock, and its interests may conflict with those of our other shareholders.

As of March 21, 2018, APEG Energy II, L.P. beneficially owned approximately 46.8% of our outstanding common stock, consisting of 5,819,270 shares of our common stock. As a result, APEG Energy II, L.P. is able to exercise significant influence over matters requiring stockholder approval, including the election of directors, the adoption or amendment of provisions in our charter and bylaws, the approval of mergers and other significant corporate transactions. The interests of APEG Energy II, L.P. with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities, may conflict with the interests of our other stockholders.

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. 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, 2017, our common stock has traded as high as $1.63 per share and as low as $0.64 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 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.

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 of the 12-month period prior to the end of the reporting period. Reserve estimates as of December 31, 2017, 2016 and 2015 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:

	2017	2016	2015
Oil (per Bbl)	$51.34	$42.75	$50.28
Gas (per Mcfe)	$2.98	$2.48	$2.59

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,								
	2017 [1]			**2016** [1]			**2015** [1]		
	Oil (Bbl)	Gas (Mcf)	Total (BOE)	Oil (Bbl)	Gas (Mcf)	Total (BOE)	Oil (Bbl)	Gas (Mcf)	Total (BOE)
Proved developed	676,030	888,507	824,115	657,280	1,379,170	887,142	1,248,750	2,068,190	1,593,448
Proved undeveloped	-	-	-	-	-	-	366,430	409,740	434,720
Total proved reserves	676,030	888,507	824,115	657,280	1,379,170	887,142	1,615,180	2,477,930	2,028,168

(1) Our reserve estimates as of December 31, 2017, 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.

As of December 31, 2017, our proved reserves totaled 824,115 BOE, of which 100% were classified as proved developed. On a BOE basis, approximately 82% of the total is derived from 676,030 Bbls of oil and 18% is derived from 888,507 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, 2017 and December 31, 2016, we did not book any proved undeveloped reserves. During 2015 our proved undeveloped reserves were 434,720 BOE as of December 31, 2015. The main driver of the Company not booking any proved undeveloped reserves was primarily due to the continued depression in global commodity prices throughout 2017.

As of December 31, 2017, we do not have any material amounts of proved undeveloped reserves that have remained undeveloped for five years or more from the time such reserves were initially categorized. As a result of the continued depressed oil price environment in 2017, we did not incur any capital expenditures to convert proved undeveloped reserves to producing status and we do not have existing plans to incur capital expenditures for this purpose in 2018.

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, 2017, 2016 and 2015.

	2017	2016	2015
Production Volume			
Oil (Bbls)	111,914	132,429	221,650
Natural gas (Mcfe)	448,571	477,351	553,505
BOE	186,676	211,988	313,901
Daily Average Production Volume			
Oil (Bbls per day)	307	363	607
Natural gas (Mcfe per day)	1,229	1,308	1,516
BOE per day	511	581	860
Net prices realized			
Oil per Bbl	$45.16	$35.41	$40.82
Natural gas per Mcfe	3.32	2.29	2.26
Oil and natural gas per BOE	35.06	27.11	32.80
Operating Expenses per BOE			
Production costs	$18.22	$12.87	$23.42
Depletion, depreciation and amortization	3.86	11.93	26.80

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 annual report on Form 10-K.

The following table provides a regional summary of our production for the years ended December 31, 2017, 2016 and 2015:

	2017 Oil (Bbl)	Gas (Mcfe)	Total (BOE)	2016 Oil (Bbl)	Gas (Mcfe)	Total (BOE)	2015 Oil (Bbl)	Gas (Mcfe)	Total (BOE)
Williston Basin (North Dakota)	90,534	128,640	111,974	103,423	149,944	128,774	163,380	151,191	188,579
Eagle Ford / Buda (South Texas)	18,281	130,095	39,964	25,192	136,441	47,932	53,149	232,094	91,831
Austin Chalk (South Texas)	3,099	1,960	3,426	3,633	1,347	3,858	4,860	4,190	5,558
Gulf Coast (Louisiana and Texas)	-	187,876	31,312	180	189,619	31,424	261	166,030	27,933
Total	111,914	448,571	186,676	132,428	477,351	211,988	221,650	553,505	313,901

33

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, 2017, 2016 and 2015.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	0	0	0	0	13.0	0.5
Non-productive	-	-	-	-	-	-
Sub-total	0	0	0	0	13.0	0.5
Exploratory wells:						
Productive	1	0.06	0	0	1.0	0.3
Non-productive	-	-	-	-	-	-
Sub-total	1	0.06	0	0	1.0	0.3
Total	1	0.06	0	0	14.0	0.8

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, 2017.

	Gross Producing Wells			Net Producing Wells			Average Working Interest		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
North Dakota	89	-	89	3.97	-	3.97	4.5 %	0.0 %	4.5 %
Texas	36	-	36	9.75	-	9.75	27.9%	0.0 %	27.9%
Louisiana	-	1	1	-	0.17	0.17	-	17.0%	17.0%
Total	125	1	126	13.72	0.17	13.89	11.2%	17.0%	11.3%

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, 2017, 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, 2017.

Area	Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
Williston Basin (North Dakota):						
Rough Rider Prospect	19,200	456	-	-	19,200	456
Yellowstone and SEHR Prospects	35,840	475	-	-	35,840	475
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	1,508	-	-	12,013	1,508
Big Wells Prospect	240	36	3,242	397	3,482	433
Carrizo Creek and South McKnight Prospects	640	213	1,994	126	2,634	339
Total	89,842	4,221	5,236	523	95,078	4,744

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. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have commenced. As of December 31, 2017, all of our acreage in North Dakota, Texas, and Louisiana is held by production.

Present Activities. As of March 28, 2018 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 building is rented to non-affiliates and government agencies; we are considering an outright sale of the property.

In addition, we own three city lots covering 13.84 acres adjacent to our office building in Riverton, 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"). 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. 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.

35

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. We received the final tranche of shares in November 2017 which resulted in the issuance of 24,942,000 additional shares of Anfield with a market value of $1.0 million. 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. The mark-to-market valuation does not affect the Company’s earnings. On December 22, 2017, Anfield implemented a reverse split of its common shares at a ratio of 10:1 and our holdings have been adjusted accordingly. At December 31, 2017, 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, 2017.

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 or resolved at December 31, 2017 and developments in those proceedings through March 28, 2018 are summarized below.

Statoil ASA

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's position in this matter was resolved on October 4, 2017 when the Company, Energy One LLC and Statoil Oil and Gas LP ("Statoil") entered into a purchase and sale agreement pursuant to which, the Company assigned, sold, and conveyed certain non-operated assets in the Williston Basin, North Dakota in consideration for the elimination of $4.2 million in outstanding liabilities and payment by Statoil to the Company of $2.0 million in cash.

The Company had historically recognized a contingent liability associated with uncertain ownership interests 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 and group wells and the timing of reversionary interests. This contingent liability was resolved on October 4, 2017 as part of the announced divestment of certain Company assets to Statoil.

Reformed Assignments

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 matter was settled on July 7, 2017 with the court ruling in favor Brigham and therefore the Company will retain all interests in all subject leases.

Quiet Title Action – Willerson Lease

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, the Willerson lessor 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. The matter has settled in 2017 in favor of the Willerson lessor with the Company's portion of such settlement being $75,000 plus related legal fees of $165,000 as reflected in the Company's financial statements under "Professional fees, insurance and other" as of December 31, 2017.

Arbitration of Employment Claim

A former employee has claimed that the Company owes 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 parties in March 2016. This matter was settled in May 2017 for $175,000 plus non-essential equipment of $11,000 as reflected in the Company's financial statements under "Rental and other income/(loss)" as of December 31, 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, 2017:		
First quarter	$0.77	$1.27
Second quarter	0.64	0.99
Third quarter	0.67	0.84
Fourth quarter	0.75	1.63
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

As of March 21, 2018, the closing sales price was $1.12 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.

Holders

As of March 21, 2018, we had 12,440,927 shares of common stock issued and outstanding.

Dividends

We did not declare or pay any cash dividends on common stock during fiscal years 2017, 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.*

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 and Item 8 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,				
	2017	2016	2015	2014	2013
	(Dollars in Thousands, Except Per Share Amounts)				
Revenue from oil and gas sales	$6,545	$5,746	$10,296	$32,379	$33,647
Total operating expenses	7,533	17,675	79,360	31,759	35,322
Operating Income/(loss)	(988)	(11,929)	(69,064)	620	(1,675)
Other income (expense)	(372)	257	1,780	397	(2,840)
Gain (loss) from continuing operations	(1,360)	(11,672)	(67,284)	1,017	(4,515)
Loss from discontinued operations	-	(2,448)	(25,612)	(3,108)	(2,864)
Net Loss	$(1,360)	$(14,120)	$(92,896)	$(2,091)	$(7,379)
Earnings/(loss) per share- basic					
Continuing operations	$(0.23)	$(2.45)	$(14.38)	$0.04	$(0.98)
Discontinued operations	-	(0.51)	(5.48)	(0.12)	(0.62)
Total	$(0.23)	$(2.96)	$(19.86)	$(0.08)	$(1.60)
Earnings (loss) per share- diluted					
Continuing operations	$(0.23)	$(2.45)	$(14.38)	$0.04	$(0.98)
Discontinued operations	-	(0.51)	(5.48)	(0.12)	(0.62)
Total	$(0.23)	$(2.96)	$(19.86)	$(0.08)	$(1.60)
Weighted average shares outstanding					
Basic & Diluted	5,899,802	4,768,013	4,677,500	4,638,833	4,612,667

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(Dollars in Thousands)				
Cash flow data					
Net cash provided by (used in):					
Operating activities	$(892)	$(1,405)	$2,504	$23,737	$20,143
Investing activities	1,701	(194)	(565)	(19,542)	(18,219)
Financing activities	(50)	1,211	(154)	(3,055)	(10,821)
Discontinued operations	-	(448)	(2,441)	(2,985)	11,927
Balance sheet data (at end of year)					
Working capital (deficit)	$4,336	$(6,043)	$(9,778)	$(654)	$5,970
Oil and gas properties, using full cost method	7,615	9,858	23,432	88,269	86,922
Total assets	15,316	16,767	33,132	123,523	126,801
Long-term debt, less current portion	937	-	-	6,000	9,000
Total shareholders' equity	10,662	3,758	15,475	107,395	109,057

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.

Recent Developments

On January 5, 2018 the Company entered into a common stock sales agreement with a financial institution pursuant to which we may sell from time to time, at our option, through the sales agent, shares of common stock representing an aggregate offering price of up to $2.5 million. Sales of the shares, if any, will be made in transactions that are deemed to be “at the market offerings” as defined in Rule 415 under the Securities Act of 1933, as amended.

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, 2017 and 2016 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, 2017 and 2016

During the year ended December 31, 2017, we recorded a net loss of $1.4 million as compared to a net loss of $14.1 million for the year ended December 31, 2016. Our loss from continuing operations was $1.4 million for the year ended December 31, 2017 compared to a loss from continuing operations of $11.7 million for the year ended December 31, 2016. In the following sections we discuss our revenue, operating expenses, non-operating income, and discontinued operations for the year ended December 31, 2017 compared to the year ended December 31, 2016.

Revenue. Presented below is a comparison of our oil and gas sales, production quantities and average sales prices for the years ended December 31, 2017 and 2016 (dollars in thousands, except average sales prices):

	2017	2016	Change Amount	Percent	
Revenue:					
Oil	$5,054	$4,689	$365	8	%
Gas	1,491	1,057	434	41	%
Total	$6,545	5,746	$799	14	%
Production quantities:					
Oil (Bbls)	111,914	132,429	(20,515)	-15	%
Gas (Mcfe)	448,571	447,351	1,220	0	%
BOE	186,676	211,988	(25,312)	-12	%
Average sales prices:					
Oil (Bbls)	$45.16	$35.41	$9.75	28	%
Gas (Mcfe)	3.32	2.29	1.03	45	%
BOE	35.06	27.11	7.95	29	%

The increase in our oil sales of $0.8 million for the year ended December 31, 2017 resulted from a 28% increase in the average sales price received during 2017 compared to 2016 which offset a 12% reduction in production quantities during 2017 compared to 2016. The decrease in our production quantities for the year ended December 31, 2017 was primarily attributable to the natural decline of production from existing wells combined with strategic asset divestments completed by the Company during 2017. During 2017, 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 $7.00 per barrel. We expect our price differentials relative to WTI to strengthen going forward (with the amount of the differential varying over time) due to additional takeaway capacity opened to eastern Canada and U.S. Markets and transportation on rail gradually declining. The market optionality on the crude oil gathering systems allows operators to shift volumes between pipeline and rail markets to optimize price realizations.

For the year ended December 31, 2017, we produced 186,676 BOE, or an average of 511 BOE per day, as compared to 211,988 BOE or 581 BOE per day in 2016. Production for our Williston Basin properties decreased by 16,800 BOE during 2017, which is a 13% reduction compared to 2016. This decrease of 13% is primarily due to the previously discussed October 2017 Statoil asset divestiture combined with normal production declines. Production for our Eagle Ford and Buda properties in South Texas decreased by 7,968 BOE during 2017, which is a 20% reduction compared to 2016. This reduction was attributable to the normal decline in production for wells in this area. Also, we did not participate in further drilling in this area during 2017.

Oil and Gas Production Costs. Presented below is a comparison of our oil and gas production costs for the years ended December 31, 2017 and 2016 (dollars in thousands):

	2017	2016	Change Amount	Percent
Production taxes and other expenses	$1,034	$790	$244	31 %
Lease operating expense	2,368	1,938	430	22 %
Total	$3,402	$2,728	$674	25 %

For the year ended December 31, 2017, production taxes increased by $0.2 million compared to 2016. The increase in production taxes is primarily a result of increased revenue from oil and gas sales. For the year ended December 31, 2017, lease operating expense increased by $0.4 million which was primarily due to the increase in workover activity on existing wells as a result of improved commodity pricing allowing for better economic returns.

Depreciation, depletion and amortization. Our DD&A rate for the year ended December 31, 2017 was $3.86 per BOE compared to $11.93 per BOE for 2016. 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 in 2016.

Impairment of oil and gas properties. During the years ended December 31, 2017 and 2016, we recorded impairment charges related to our oil and gas properties of $0 and $9.6 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 in 2016.

Our quarterly reserve reports are prepared based on first of the month, trailing 12-month average for benchmark oil and gas prices adjusted for differentials from posted prices. The weighted average oil price used to prepare reserve estimates and to calculate the Full Cost Ceiling limitation for the first quarter of 2018 is expected to increase due to the increase in oil and gas prices during that period. Assuming other variables remain substantially unchanged, we do not expect to record an impairment charge during the first quarter of 2018.

General and Administrative Expenses. Presented below is a comparison of our general and administrative expenses for the years ended December 31, 2017 and 2016 (dollars in thousands):

	2017	2016	Change Amount	Percent	
Compensation and benefits, including directors	$741	$640	$101	16	%
Stock-based compensation	323	213	110	52	%
Employee severance costs	-	3	(3)	-100	%
Professional fees, insurance and other	2,314	1,994	320	16	%
Total	$3,378	$2,850	$528	19	%

General and administrative expenses increased by $0.5 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. This increase was primarily attributable to an increase of $0.3 million, $0.1 million, and $0.1 million in professional fees, compensation and benefits, and stock-based compensation, respectively. The primary driver in the increase in professional fees were costs incurred during the Company's negotiations with the sole lender of its Credit Facility during the first half of 2017.

Non-Operating Income (Expense). Presented below is a comparison of our non-operating income (expense) for the years ended December 31, 2017 and 2016 (dollars in thousands):

	2017	2016	Change Amount	Percent
Realized gain on commodity price risk derivatives	$135	$1,440	$(1,305)	-91 %
Unrealized loss on commodity price risk derivatives	(161)	(1,634)	1,473	-90 %
Gain on sale of assets	3	102	(99)	-97 %
Gain on sale of oil and gas properties	4,318	-	4,318	N/A
Loss on debt for equity conversion	(4,440)	-	(4,440)	N/A
Gain on investments	777	750	27	4 %
Rental and other expense	(321)	(169)	(152)	90 %
Gain (loss) on Warrant Revaluation	(170)	210	(380)	-181 %
Interest expense	(513)	(442)	(71)	16 %
Total other income/(loss)	$(372)	$257	$(629)	-245 %

We recognized a realized gain on commodity price risk derivatives of $0.1 million for the year ended December 31, 2017 compared to a gain of $1.4 million for 2016. We recognized an unrealized loss on commodity price risk derivatives of $0.2 million for the year ended December 31, 2017 compared to a loss of $1.6 million for 2016.

During the year ended December 31, 2017, we recorded a gain on the sale of oil and gas properties of $4.3 million associated with the October 2017 StatOil asset divestiture. We recognized a non-cash debt for equity conversion loss of $4.4 million due to the Company’s stock price increasing during the period between the October 2017 debt for equity conversion transaction announcement and December 2017 debt for equity conversion transaction closing.

During the years ended December 31, 2017 and 2016, we recorded a gain on investment of $1.0 million from the receipt of shares related to the disposition of a portion of our mining assets. We recognized a loss on rental and other income of $0.3 million which was primarily driven by a settlement with a former employee combined with maintenance costs associated with our Riverton, Wyoming office building, both of which are included under the category “Rental and other income (loss)” on the Consolidated Statements of Operations and Comprehensive Loss. During the year ended December 31, 2017, we realized a loss 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.

Interest expense increased by $0.1 million during the year ended December 31, 2017 compared to 2016. This increase was primarily attributable to an increase in our weighted average borrowing for 2017 which was partially offset by a write-off of debt issuance costs associated with the amendment of our credit agreement during the third quarter of 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, 2017 and 2016 we recognized no impairment charges. During the years ended December 31, 2017, there were no expenses associated with any discontinued operations. For the year ended December 31, 2016, 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 and the total operating and holding expenses amounted to $2.1 million. 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 consideration.

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):

	2016	2015	Change 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)	-32 %
Average sales prices:				
Oil (Bbls)	$35.41	$40.82	$(5.41)	-13 %
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 13% 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. The reduction is consistent with normal production declines with wells located throughout the Williston Basin and 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. Also, 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):

	2016	2015	Change Amount	Percent
Production taxes and other expenses	$790	$1,021	$(231)	-23 %
Lease operating expense	1,938	6,331	(4,393)	-69 %
Total	$2,728	$7,352	$(4,624)	-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 first of the month, trailing 12-month average for benchmark oil and gas prices adjusted for differentials from posted prices

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):

			Change	
	2016	2015	Amount	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)	-99 %

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	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%

46

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.

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.

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, 2017, 2016 and 2015, in thousands:

	2017	2016	2015
Loss from continuing operations (GAAP)	$(1,360)	$(11,672)	$(67,284)
Impairment of oil and gas properties	-	9,568	57,676
Depreciation, depletion and amortization	753	2,529	8,412
(Gain)/loss on investments	(777)	(750)	68
Stock-based compensation	323	213	948
Employee severance costs	-	3	504
(Gain)/loss on sale of assets	3	(102)	(121)
Gain on sale of oil and gas property	(4,318)	-	-
Loss on conversion of debt to equity	4,440	-	-
(Gain)/loss on warrant revaluation	170	(210)	-
Interest expense	513	442	263
Adjusted EBITDAX (Non-GAAP)	$(253)	$21	$466

Liquidity and Capital Resources

The following table sets forth certain measures about our liquidity as of December 31, 2017 and 2016, in thousands:

	2017	2016	Change
Cash and equivalents	$3,277	$2,518	$759
Working capital surplus (deficit) [1]	4,336	(6,043)	10,379
Oil and gas standardized measure [2]	9,253	6,747	2,506
Total assets	15,316	16,767	(1,451)
Outstanding debt under Credit Facility	1,537	6,000	(4,463)
Borrowing base under Credit Facility	6,000	6,000	-
Total shareholders' equity	10,662	3,758	6,904
Select Ratios			
Current ratio [3]	3.74 to 1.00	0.45 to 1.00	
Debt to equity ratio [4]	0.14 to 1.00	1.59 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, 2017, we have a working capital surplus of $4.3 million compared to a working capital deficit of $6.0 million as of December 31, 2016, an improvement of $10.3 million. This improvement was primarily attributable to (i) the reclassification of historically disputed property ownership interests due to a settlement with the operator and (ii) the reclassification of outstanding debt associated with the Credit Facility being reclassified as a long-term liability.

Our sole source of debt financing is a revolving Credit Facility with APEG Energy II, LP. The borrowing base has been held constant at $6.0 million as of December 31, 2017 and 2016. Outstanding borrowings as of December 31, 2017 were $1.5 million, and the Company had borrowing availability of $4.5 million as of December 31, 2017. As of December 31, 2017, we were in compliance will all financial covenants associated with the Credit Facility.

As of December 31, 2017, we had cash and equivalents of $3.3 million.

If we have needs for financing in 2018, alternatives that we will consider in addition to cash flow from ongoing operations would be potentially 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.

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2017 and 2016 (in thousands):

	2017	**2016**	**Change**
Net cash provided by (used in):			
Operating activities	$(892)	$(1,405)	$513
Investing activities	1,701	(194)	1,895
Financing activities	(50)	1,211	(1,261)
Discontinued operations	-	(448)	448

Operating Activities. Cash used in operating activities for the year ended December 31, 2017 was $0.9 million as compared to cash used in operating activities of $1.4 million for 2016, a decrease of $0.5 million. This decrease is primarily related to the increase in our oil and gas sales for the year ended December 31, 2017 as compared to 2016.

Investing Activities. Cash generated in investing activities for the year ended December 31, 2017 was cash provided of $1.7 million as compared to cash used in investing activities of $0.2 million for 2016, an improvement of $1.9 million. The increase in cash provided was primarily driven by the divestment of certain oil and gas properties during October 2017.

Financing Activities. Cash used in financing activities for the year ended December 31, 2017 was a $0.1 million as compared to cash provided by financing activities of $1.2 million for 2016, a decrease of $1.3 million. The decrease in cash provided by financing activities was primarily due to $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 for the year ended December 31, 2017 as compared to $0.4 million for 2016, an improvement of $0.4 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, 2017.

Item 8 – Financial Statements and Supplementary Data

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

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, 2017, our Chief Executive Officer and Principal Financial Officer determined that our controls were not adequate due to a lack of segregation of duties caused by limited accounting staff and resources which has impacted our ability to prevent or detect material errors in the financial statements including the implementation of new accounting standards. 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, 2017, as it relates to the timely implementation of the Company's review of key controls.

The Company plans on addressing this weakness by filling the vacancies 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, 2017. 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, 2017 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. 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, 2017 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 Stockholders and the Board of Directors of

U.S. Energy Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheet of U.S. Energy Corp. and subsidiary (the "Company") as of December 31, 2017, the related consolidated statements of operations and comprehensive loss, stockholders' equity and cash flows for the year then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2017, and the consolidated results of its operations and its cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting 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.

Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Moss Adams LLP

Denver, Colorado
March 28, 2018

We have served as the Company's auditor since 2017.

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 sheet of U.S. Energy Corp. and subsidiary as of December 31, 2016, and the related consolidated statements of operations and comprehensive loss, stockholders' equity and cash flows for each of the two years in the period ending December 31, 2016. 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 the results of their operations and their cash flows for each of the two years in the period 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

53

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

DECEMBER 31, 2017 AND 2016

(In Thousands, Except Share and Per Share Amounts)

	2017	2016
ASSETS		
Current assets:		
Cash and equivalents	$3,277	$2,518
Oil and gas sales receivable	687	562
Discontinued operations - assets of mining segment	114	114
Assets available for sale	653	653
Marketable securities	876	947
Refundable deposits	250	-
Other current assets	61	95
Total current assets	5,918	4,889
Oil and gas properties under full cost method:		
Unevaluated properties and exploratory wells in progress	4,664	4,664
Evaluated properties	86,313	87,834
Less accumulated depreciation, depletion and amortization	(83,362)	(82,640)
Net oil and gas properties	7,615	9,858
Other assets:		
Property and equipment, net	1,717	1,864
Other assets	66	156
Total other assets	1,783	2,020
Total assets	$15,316	$16,767
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities:		
Payable to major operator	$-	$2,710
Contingent ownership interests	-	1,430
Other	707	743
Related party payable	50	-
Accrued compensation and benefits	64	49
Current portion of long-term debt	600	6,000
Liabilities from derivative contracts	161	-

Total current liabilities	1,582	10,932
Noncurrent liabilities:		
Long-term debt, less current portion	937	-
Asset retirement obligations	913	1,045
Warrant liability	1,200	1,030
Other liabilities	22	2
Total noncurrent liabilities	3,072	2,077
Commitments, contingencies, and related party transactions (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 2017; liquidation preference of $2,527 as of December 31, 2017	1	1
Common stock, $0.01 par value; unlimited shares authorized; 11,820,057 and 6,134,506 shares issued and outstanding, respectively	118	61
Additional paid-in capital	136,631	127,576
Accumulated deficit	(125,185)	(123,825)
Other comprehensive loss	(903)	(55)
Total shareholders' equity	10,662	3,758
Total liabilities and shareholders' equity	$15,316	$16,767

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, 2017, 2016 AND 2015

(In Thousands, Except Share and Per Share Amounts)

	2017	2016	2015
Revenue:			
Oil	$5,054	$4,689	$9,047
Natural gas and liquids	1,491	1,057	1,249
Total revenue	6,545	5,746	10,296
Operating expenses:			
Oil and gas operations:			
Production costs	3,402	2,728	7,352
Depreciation, depletion and amortization	753	2,529	8,412
Impairment of oil and gas properties	-	9,568	57,676
General and administrative:			
Compensation and benefits, including directors and contract employees	741	640	2,602
Stock-based compensation	323	213	948
Employee severance costs	-	3	504
Professional fees, insurance and other	2,314	1,994	1,866
Total operating expenses	7,533	17,675	79,360
Operating Loss	(988)	(11,929)	(69,064)
Other income (expense):			
Realized gain (loss) on commodity price risk derivatives	135	1,440	(75)
Unrealized gain (loss) on commodity price risk derivatives	(161)	(1,634)	1,634
Gain on sale of assets	3	102	121
Gain on sale of oil and gas properties	4,318	-	-
Loss on debt for equity conversion	(4,440)	-	-
Gain (loss) on investments	777	750	(68)
Rental and other income (loss)	(321)	(169)	431
Warrant revaluation gain (loss)	(170)	210	-
Interest expense	(513)	(442)	(263)
Total other income (expense)	(372)	257	1,780
Loss from continuing operations	(1,360)	(11,672)	(67,284)

Discontinued operations:			
Discontinued operations	-	(2,448)	(2,992)
Impairment loss on discontinued operations	-	-	(22,620)
Loss from discontinued operations	-	(2,448)	(25,612)
Net loss	(1,360)	(14,120)	(92,896)
Change in fair value of marketable equity securities, net of tax	(848)	(55)	56
Comprehensive loss	$(2,208)	$(14,175)	$(92,840)
Loss from continuing operations	(1,360)	(11,672)	(67,284)
Accrued dividends related to Series A Convertible Preferred Stock	(514)	(232)	-
Loss from continuing operations applicable to common shareholders	(1,874)	(11,904)	(67,284)
Loss per share- basic and diluted			
Continuing operations	$(0.23)	$(2.50)	$(14.38)
Discontinued operations	-	(0.51)	(5.48)
Total	$(0.23)	$(3.01)	$(19.86)
Weighted average shares outstanding			
Basic and diluted	5,899,802	4,768,013	4,677,500

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

55

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

(In Thousands, Except Share Amounts)

	Common Stock		**Preferred Stock**		Additional **Paid-in**	Accumulated	Accumulated Other Comprehensive	
	Shares	Amount	Shares	**Amount**	**Capital**	Deficit	Loss	Total
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)
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)
Stock-based compensation	-	-	-	-	213	-	-	213
Net loss	-	-	-	-	-	(14,120)	-	(14,120)

Balances, December 31, 2016	6,134,506	$ 61	50,000	$ 1	$ 127,576	$ (123,825)	$ (55)	$ 3,758
Placement fees recorded in equity	-	-	-	-	(114)	-	-	(114)
Revised 2016 option grants	(151,008)	(1)	-	-	196	-	-	195
Issued shares to creditor	5,819,270	58	-	-	8,845	-	-	8,903
Stock-based compensation	-	-	-	-	128	-	-	128
Unrealized loss on marketable equity securities	-	-	-	-	-	-	(848)	(848)
Net loss	-	-	-	-	-	(1,360)	-	(1,360)
Balances, December 31, 2017	11,802,768	$ 118	50,000	1	$ 136,631	$ (125,185)	$ (903)	$ 10,662

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

56

U.S. ENERGY CORP. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2017, 2016 AND 2015

(In Thousands)

	2017	2016	2015
Cash flows from operating activities:			
Net loss	$(1,360)	$(14,120)	$(92,896)
Loss from discontinued operations	-	2,448	25,612
Loss from continuing operations	(1,360)	(11,672)	(67,284)
Adjustments to reconcile loss from continuing operations to net cash provided by / (used in) operating activities:			
Depreciation, depletion, accretion, and amortization	890	2,529	8,557
Debt amortization	-	-	-
Impairment of oil and gas properties	-	9,568	57,676
Change in fair value of oil price risk derivative	161	1,634	(1,634)
Interest change in Major Operator	(141)	(1,476)	-
Gain on sale of oil and gas properties	(4,318)	-	-
Loss on conversion of debt to equity	4,440	-	-
Gain on sale of assets	(3)	(102)	(121)
Stock-based compensation and services	323	213	948
(Gain)/loss on Warrants	170	(210)	-
Other	(704)	(372)	(110)
Changes in operating assets and liabilities:			
Decrease (increase) in:			
Oil and gas sales receivable	(125)	580	2,034
Other assets	(159)	86	63
Increase (decrease) in:			
Accounts payable	(77)	(1,050)	1,126
Major operator overpayments	-	-	1,429
Accrued compensation and benefits	11	(1,133)	(188)
Other liabilities	-	-	8
Net cash provided by / (used in) operating activities	(892)	(1,405)	2,504
Cash flows from investing activities:			
Capital expenditures	(299)	(194)	(3,620)
Proceeds from sale of oil and gas properties and other	2,000	-	264
Proceeds from settlement of property litigation	-	-	1,500
Net change in restricted investments	-	-	1,291
Net cash provided by / (used) in investing activities:	1,701	(194)	(565)

Cash flows from financing activities:			
Issuance of common stock	(27)	1,317	-
Redemption of common stock	-	(3)	(29)
Payments for debt issuance costs	(23)	(103)	(125)
Net cash provided by / (used in) financing activities	(50)	1,211	(154)
Discontinued operations:			
Net cash used in operating activities	-	(448)	(2,440)
Net cash used in investing activities	-	-	(1)
Net cash used in discontinued operations	-	(448)	(2,441)
Net increase (decrease) in cash and equivalents	759	(836)	(656)
Cash and equivalents, beginning of year	2,518	3,354	4,010
Cash and equivalents, end of year	$3,277	$2,518	$3,354

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, 2017, 2016 AND 2015

(In Thousands)

	2017	2016	2015
Supplemental disclosures of cash flow information:			
Cash payments for income taxes	$-	$-	$-
Cash payments for interest	$451	$442	$210
Non-cash investing and financing activities:			
Unrealized gain/(loss) on marketable equity securities	$(848)	$(55)	$56
Fees incurred during equity for debt conversion and common stock sales agreement	114	-	-
Debt Long Term to Short Term	600	-	-
Payable to Major Operator forgiven	3,999	-	-
Increase (decrease) in accrued capital expenditures for oil and gas properties	$48	$112	$(112)
Asset Retirement obligations assumed by Purchaser	(167)	(1)	-
Net additions to oil and gas properties through asset retirement obligations	3	$-	$61

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

U.S. ENERGY CORP. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in Thousands, Except Per Share Amounts)

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 consists 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 receivables 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, 2017 and 2016, 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.

U.S. ENERGY CORP. AND SUBSIDIARIES

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 were not economic due to permanent decreases in market prices of commodities, excessive production costs, depletion of the mineral resource, or other factors.

Impairment of 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, 2017, 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, 2017 and 2016, 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.

Recent Accounting Pronouncements

Revenue recognition. In May 2014, the FASB and the International Accounting Standards Board (IASB) issued a joint revenue recognition standard, ASU 2014-09. The new standard removes inconsistencies in existing standards, changes the way companies recognize revenue from contracts with customers, and increases disclosure requirements. The codification was amended through additional ASUs and, as amended, requires companies to recognize revenue to depict the transfer of goods or services to customers in amounts that reflect the consideration to which the company expects to be entitled in exchange for those goods or services. The guidance is effective for annual and interim periods beginning after December 15, 2017. The standard is required to be adopted using either the full retrospective approach, with all prior periods presented adjusted, or the modified retrospective approach, with a cumulative adjustment to retained earnings on the opening balance sheet. The Company will adopt the new standard utilizing the modified retrospective approach. The Company had no impact on the financial statements after adoption of this ASU.

Financial instruments. In January 2016, the FASB issued Accounting Standards Update No. 2016-01, *Recognition and Measurement of Financial Assets and Financial Liabilities* ("ASU 2016-01"), which requires that most equity instruments be measured at fair value with subsequent changes in fair value recognized in net income. ASU 2016-01 also impacts financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. ASU 2016-01 does not apply to equity method investments or investments in consolidated subsidiaries. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. The adoption of this guidance does not impact the Company's financial position or results of operations.

Leases. In February 2016, the FASB issued Accounting Standards Update No. 2016-02, *Leases* ("ASU 2016-02"), which requires a lessee to recognize lease payment obligations and a corresponding right-of-use asset to be measured at fair value on the balance sheet. ASU 2016-02 also requires certain qualitative and quantitative disclosures about the amount, timing and uncertainty of cash flows arising from leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Statement of cash flows. In August 2016, the FASB issued Accounting Standards Update No. 2016-15, *Statement of Cash Flows* ("ASU 2016-15"), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. The adoption of this guidance will not impact the Company's financial position or results of operations, but could result in presentation changes on the Company's statement of cash flows.

Business combinations. In January 2017, the FASB issued Accounting Standards Update No. 2017-01, *Clarifying the Definition of a Business* ("ASU 2017-01"), which provides guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 requires entities to use a screen test to determine when an integrated set of assets and activities is not a business or if the integrated set of assets and activities needs to be further evaluated against the framework. ASU 2017-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Stock-based compensation. In May 2017, the FASB issued Accounting Standards Update No. 2017-09, *Scope of Modification Accounting* ("ASU 2017-09"), which provides guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. The adoption of ASU 2017-09 will become effective for annual periods beginning after December 15, 2017, and the Company is currently evaluating the impact that it will have on its financial position, cash flows and results of operations.

Hedging activities. On August 28, 2017, the FASB issued Accounting Standards Update (ASU) 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities. The amendments in ASU 2017-12 apply to any entity that elects to apply hedge accounting in accordance with U.S. generally accepted accounting principles (U.S. GAAP). The amendments in ASU 2017-12 take effect for public business entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. For all other entities, the amendments take effect for fiscal years beginning after December 15, 2019, and interim periods beginning after December 15, 2020. Early adoption is permitted. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Financial instruments with characteristics of liabilities and equity. On July 13, 2017, the FASB has issued a two-part Accounting Standards Update (AS), No. 2017-11, I. Accounting for Certain Financials Instruments with Down Round Features and II. Replacement of the Indefinitie Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interest with a Scop Exception. The ASU is effective for public business entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

2. LIQUIDITY

As of December 31, 2017, the Company had a working capital surplus of $4.3 million and an accumulated deficit of $125.2 million. Additionally, the Company incurred a net loss of $1.4 million for the year ended December 31, 2017. As of December 31, 2017, the Company was in full compliance with all covenants under its credit agreement.

During the 2017, the Company completed the following actions which are expected to improve the Company's operating results going forward while increasing the ability of the Company to grow in the current oil and gas industry price environment.

On October 3, 2017, U.S. Energy Corp. (the "Company"), the Company's wholly owned subsidiary Energy One LLC and Statoil Oil and Gas LP ("Statoil") entered into a purchase and sale agreement (the "Purchase Agreement"), under which, the Company assigned certain non-operated assets in the Williston Basin, North Dakota in consideration for the elimination of $4.0 million in outstanding liabilities and payment by Statoil to the Company of $2.0 million in cash. U.S. Energy has historically accounted for the eliminated liabilities on the Company's balance sheet under "Payable to major operator" and "Contingent ownership interests." The Purchase Agreement has an effective date of August 1, 2017 and was unanimously approved by the board of directors of the Company.

On December 27, 2017, U.S. Energy Corp. received shareholder approval for the exchange agreement ("Exchange Agreement") by and among the Company, the Company's wholly owned subsidiary Energy One LLC and APEG Energy II, L.P., ("APEG"), an entity controlled by Angelus Private Equity Group, LLC pursuant to which, on the terms and subject to the conditions of the Exchange Agreement, APEG exchanged $4,463,380 of outstanding borrowings under the Company's Credit Facility, for 5,819,270 new shares of common stock of the Company, par value $0.01 per share, representing an exchange price of $0.767 representing a 1.3% premium over the 30-day volume weighted average price of the Company's common stock on September 20, 2017 (the "Exchange Shares"). Accrued, unpaid interest on the Credit Facility held by APEG was paid in cash at the closing of the transaction. Following the close of the transaction, APEG holds approximately 49.3% of the outstanding Common Stock of U.S. Energy. The Transaction was approved by the Company's shareholders and closed in the fourth quarter of 2017. Additionally, the transaction was recorded based on a $1.53 stock price which represented the Company's stock price on the date of shareholder approval.

As of December 31, 2017, the Company had cash and equivalents of $3.3 million. Management believes overhead and mining expense eliminations have positioned the Company to survive the continued low commodity price environment. However, there can be no assurance that the Company will be able to complete future financings, dispositions or acquisitions on acceptable terms or at all.

Our strategy is to continue to (1) maintain adequate liquidity and selectively participate in new drilling and completion activities, subject to economic and industry conditions, (2) pursue acquisition and disposition opportunities, and (3) evaluate various avenues to strengthen our balance sheet and improve our liquidity position. We expect to fund any near-term capital requirements and working capital needs from existing cash on hand. Because production from existing oil and natural gas wells declines over time, further reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future.

3. COMMODITY PRICE RISK DERIVATIVES

The Company's wholly-owned subsidiary Energy One has entered into commodity price derivative contracts ("economic hedges") with BP Energy. The derivative contracts are priced based on West Texas Intermediate ("WTI") quoted prices for crude oil and Henry Hub quoted prices for natural gas. 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. Presented below is a summary of outstanding crude oil and natural gas swaps as of December 31, 2017.

	Action	Begin	End	Quantity (bbls/d)	Price
Crude oil price swaps	Bought	1/1/18	6/30/18	150	52.20

	Action	Begin	End	**Quantity (mcf/d)**	Price
Natural gas price swaps	Bought	1/1/18	12/31/18	2,500	3.01
Natural gas price swaps	Sold	1/1/18	12/31/18	2,000	2.98

We recognized a realized gain on commodity price risk derivatives of $0.1 million for the year ended December 31, 2017 compared to a realized gain of $1.4 million for 2016. We recognized an unrealized loss on commodity price risk derivatives of $0.2 million for the year ended December 31, 2017 compared to an unrealized loss of $1.6 million for 2016. As of December 31, 2017, the Company had un unrealized loss on commodity derivative contracts of $0.16 million which consisted of an unrealized loss from oil price derivatives of $0.22 million which was offset by an unrealized gain from natural gas commodity derivatives of $0.06 million.

4. OIL AND GAS PRODUCING ACTIVITIES

Divestitures

On October 3, 2017, U.S. Energy Corp. (the "Company"), the Company's wholly owned subsidiary Energy One LLC and Statoil Oil and Gas LP ("Statoil") entered into a purchase and sale agreement (the "Purchase Agreement"), pursuant to which, on the terms, and subject to the conditions of the Purchase Agreement, the Company assigned, sold, and conveyed certain non-operated assets in the Williston Basin, North Dakota in consideration for the elimination of $4.0 million in outstanding liabilities to StatOil and payment by Statoil to the Company of $2.0 million in cash. U.S. Energy has historically accounted for the eliminated liabilities on the Company's balance sheet under "Payable to major operator" and "Contingent ownership interests." The Purchase Agreement was unanimously approved by the board of directors of the Company and closed on October 5, 2017, with an effective date of August 1, 2017.

A gain/loss calculation must be performed on any transaction which impacts reserves greater than 25%.The gain/loss calculation first identifies the total consideration received, followed by a fair market valuation regarding the amount of reserves sold versus the Company's remaining reserves. The purpose of the fair market valuation is to proportionately bifurcate the considerations received between the refunding of historical capitalized costs and the gain/loss calculation on the asset sale. As a result of this analysis, the Company recorded a gain of $4.3 million relate to the divestiture.

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, 2017, the Company used $51.34 per barrel for oil and $2.976 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, 2017, 2016, and 2015 impairment of the Company's oil and gas properties amounted to $0.0 million, $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, 2017 and 2016:

	2017	2016
Oil and Gas Properties		
Unevaluated properties:		
Unproved leasehold costs	$4,664	$4,664
Exploratory wells in progress	-	-
Evaluated properties in full cost pool	86,313	87,834
Less accumulated depreciation, depletion and amortization	(83,362)	(82,640)
Net capitalized costs	$7,615	$9,858

The Company's depreciation, depletion and amortization per equivalent BOE was $3.86 for 2017, $11.93 for 2016, and $26.80 for 2015.

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, 2017 and 2016, unevaluated oil and gas properties consisted solely of unproved lease acquisition costs of $4.7 million.

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.

Results of Operations

Presented below are the results of operations from oil and gas producing activities for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
Oil and gas sales	$6,545	$5,746	$10,296
Production costs	(3,402)	(2,728)	(7,352)
Depreciation, depletion and amortization	(753)	(2,529)	(8,412)
Impairment of oil and gas properties	-	(9,568)	(57,676)
Results of operations from oil and gas producing activities	$2,390	$(9,079)	$(63,144)

5. PROPERTY AND EQUIPMENT, NET

Property and equipment consists of the following as of December 31, 2017 and 2016:

	2017	2016
Real estate:		
Land	$380	$380
Buildings	4,012	4,012
Land improvements	641	641
Administrative assets:		
Computers and software	368	368
Office furniture and equipment	222	222
Vehicles and other	11	51
Total	5,634	5,674
Less accumulated depreciation	(3,917)	(3,810)
Property and equipment, net	$1,717	$1,864

Depreciation expense related to real estate and administrative assets amounted to $0.1 million respectively for the years ended December 31, 2017, 2016 and 2015, 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 re-acquisition 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 $22.6 million 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, 2017 and 2016, along with the impact of the impairment charge:

	2017	2016
Assets retained by the Company:		
Performance bonds	$114	$114
Net assets conveyed to Purchaser:		
Undeveloped mining claims	-	-
Mining equipment	-	-
Less accumulated depreciation of mining equipment	-	-
Less write-down due to impairment	-	-
Net book value of assets conveyed	-	-
Total assets of discontinued operations	$114	$114
Asset retirement obligations assumed by Purchaser	$-	

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 accrues dividends at a rate of 12.25% per annum of the Adjusted Liquidation Preference (as defined below); 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 793,000 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 2016, the Company recorded 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 recorded 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 operations are presented separately for all periods presented in the accompanying financial statements. Presented below are the components for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
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)
Mine property holding costs	-	(2,194)	(1,133)
Impairment of mining asset	-	-	(22,620)
Depreciation of mine equipment	-	-	(122)
Total expenses for mining segment	-	(2,448)	(25,612)
Total results for discontinued operations	$ -	$(2,448)	$(25,612)

7. DEBT

Energy One, a wholly-owned subsidiary the Company, has a Credit Facility with APEG Energy II, L.P. ("APEG"). As of December 31, 2017 and 2016, outstanding borrowings under the Credit Facility amounted to $1.5 million and $6.0 million, respectively. On May 2, 2017 the Amended and Restated Credit Agreement was sold, assigned and transferred between Wells Fargo Bank N.A. to APEG. U.S. Energy Corp., Energy One and APEG entered into a Limited Forbearance Agreement dated May 2, 2017. On June 28, 2017, U.S. Energy Corp., Energy One and APEG entered into a Fifth Amendment to the Credit Facility providing for, among other things, an extension of the maturity date to July 30, 2019, new financial coverage ratio covenants and a waiver with respect to any historical Company non-compliance with any and all financial covenants. As of December 31, 2017 and 2016, the borrowing base was

$6.0 million. Borrowings under the Credit Facility are secured 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 2019 if the Company remains in compliance with the covenants under the Credit Facility. The interest rate on the Credit Facility is currently fixed at 8.75%.

Energy One is required to comply with customary affirmative covenants and with certain negative covenants. The principal negative financial covenants do not permit (as the following terms are defined in the Fifth Amendment) (i) Proved Developed Producing Coverage Ratio to be less than 1.2 to 1; and (ii) the current ratio to be less than 1.0 to 1.0. As of December 31, 2017, the Company is in compliance with all Credit Facility covenants. 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.

On December 27, 2017, U.S. Energy Corp. received shareholder approval for the exchange agreement (“Exchange Agreement”) by and among the Company, the Company’s wholly owned subsidiary Energy One LLC and APEG Energy II, L.P., (“APEG”), an entity controlled by Angelus Private Equity Group, LLC pursuant to which, on the terms and subject to the conditions of the Exchange Agreement, APEG exchanged $4,463,380 of outstanding borrowings under the Company’s Credit Facility, for 5,819,270 new shares of common stock of the Company, par value $0.01 per share, representing an exchange price of $0.767 representing a 1.3% premium over the 30-day volume weighted average price of the Company’s common stock on September 20, 2017 (the “Exchange Shares”). Accrued, unpaid interest on the Credit Facility held by APEG was paid in cash at the closing of the transaction. Following the close of the transaction, APEG holds approximately 49.3% of the outstanding Common Stock of U.S. Energy. The Transaction was approved by the Company’s shareholders and closed in the fourth quarter of 2017. Additionally, the transaction was recorded based on a $1.53 stock price which represented the Company’s stock price on the date of shareholder approval.

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, 2017 and 2016:

	2016
Balance, beginning of year	$583
Adjustment to fair value	-
Payment of retirement benefits	(583)
Negotiated settlement at discount and other	-
Balance, end of year	$-

The current portion of the Company’s liability under the Retirement Plan was fully settled in 2016. 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, 2017 and 2016 was $0 and $3, 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. 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.

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, 2017 and 2016:

	2017 Oil and Gas	Mining	2016 Oil and Gas	Mining
Balance, beginning of year	$1,045	$ -	$1,038	$ 204
Accretion	32	-	33	-
Sold/Plugged	(167)	-	(26)	(204)
New drilled wells	3	-	-	-
Liabilities incurred	-	-	-	-
Balance, end of year	$913	$ -	$1,045	$ -

70

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, CONTINGENCIES, AND RELATED PARTY TRANSACTIONS

Commitments

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 was $0.1 million respectively for the years ended December 31, 2017, 2016 and 2015, respectively.

Related Party Payable. The Company had a related party payable to its Chief Executive Officer of $0.05 million as of December 31, 2017 for the reimbursement of ordinary operating expenses incurred on behalf of the Company.

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, and matters that were settled in 2017:

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. The Company's interest in this case was assigned to Statoil as part of the October 2017 asset divestiture to Statoil.

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 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's interest in this case was assigned to Statoil as part of the October 2017 asset divestiture to Statoil.

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 matter was settled on July 7, 2017 with the court ruling in favor Brigham and therefore U.S. Energy will retain all interests in all subject leases.

Quiet Title Actions. 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. The matter settled in 2017 with the Company's portion of such settlement being $75,000 plus related legal fees of $165,000 as reflected in the Company's financial statements under "Professional fees, insurance and other" as of December 31, 2017.

Arbitration of Employment Claim. A former employee claimed that the Company owes 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 parties in March 2016. This matter was settled in May 2017 for $175,000 plus non-essential equipment of $15,000 as reflected in the Company's financial statements under "Rental and other income/(loss)" as of December 31, 2017.

Contingent Ownership Interests. The Company had historically recognized a contingent liability associated with uncertain ownership interests 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 and group wells and the timing of reversionary interests. This contingent liability was resolved on October 4, 2017 as part of the divestment of certain Company assets to Statoil.

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 gross 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, 2017 the Company had a warrant liability of $1.2 million.

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, 2017, options for a total of 67,558 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, and as further amended and approved by shareholders in July 2017, reserves for issuance to the Company's employees and Directors a total of 1,533,333 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, 2017, options for a total of 292,350 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, 2017, 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, 2017, 2016 and 2015 is as follows:

	2017		2016		2015	
	Shares	**Price (1)**	Shares	**Price (1)**	Shares	**Price (1)**
Outstanding, beginning of year	390,525	$20.64	390,525	$20.64	2,276,079	$3.78
Granted	170,000	1.00	-	-	340,711	1.50
Forfeited	-	-	-	-	-	-
Expired	(170,838)	29.82	-	-	(273,768)	3.86
Exercised	-	-	-	-	-	-
Outstanding, end of year	389,687	$8.05	390,525	$20.64	2,343,022	$3.44
Shares restated after 6 to 1 split	389,687	$8.05	390,525	$20.64	390,525	$20.64
Exercisable, end of year	274,132	$10.79	376,084	$20.79	2,194,022	$3.53
Shares restated after 6 to 1 split	-	$-	-	$-	365,693	$21.17

(1) Represents the weighted average price.

No stock options were exercised during the years ended December 31, 2017, 2016, or 2015.

The following table summarizes information for stock options outstanding and for stock options exercisable at December 31, 2017:

Options Outstanding				Options Exercisable	
Number of	Exercise Price Range	Weighted	Remaining Contractual	Number of	Weighted Average

Shares	Low	High	Average	Term (years)	Shares	Exercise Price
56,786	$9.00	$9.00	$ 9.00	7.0	51,231	$ 9.00
49,504	12.48	12.48	12.48	5.5	49,504	12.48
98,396	13.92	17.10	15.01	1.8	98,396	15.01
15,001	22.62	30.24	24.03	5.5	15,001	24.03
60,000	0.72	0.72	0.72	9.6	60,000	0.72
110,000	1.16	1.16	1.16	9.9	-	-
389,687	$0.72	$30.24	$ 8.05	6.7	274,132	$ 10.79

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 $0.1 million.

For the years ended December 31, 2017, 2016 and 2015, total stock-based compensation expense associated with stock options, including the modification charge discussed above, was \$0.3 million, \$0.2 million, and \$0.9 million, respectively. As of December 31, 2017, there was \$0.1 million of unrecognized expense related to unvested stock options, which will be recognized as stock-based compensation expense through November 2019. In estimating the fair value of options, the Company used the Black-Scholes option-pricing model with the following weighted average assumptions:

	2017	2016
Expected lives (in years)	10.0	-
Risk-free interest rate	2.33%	-
Expected volatility	80.0%	-
Expected dividend yield	0.00%	-

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. In connection with the resignations of four members of the Company's Board of Directors, the restricted stock grants were amended and the members of the Board of Directors subsequently agreed to accept 33,332 fully-vested shares each, in lieu of the 58,500 share grants for a net total of 199,992 shares. The closing price of the Company's common stock on the grant date was \$1.05, resulting in an aggregate compensation charge of \$0.2 million. As of December 31, 2017, the Company had expensed the entire aggregate compensation charge over 2017 and there was \$0 of unrecognized expense related to the September 23, 2016 grants.

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 were not eligible for ESOP contributions to the extent that their annual taxable compensation exceeded \$0.3 million for 2015. In September 2016, the Company's Board of Directors agreed to terminate the ESOP, which resulted 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, 2017, we did not incur any stock-based compensation expense related to the ESOP.

12. INCOME TAXES

The Company incurred a net loss for each of the years ended December 31, 2017, 2016 and 2015, 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:

	2017	2016	2015
Income tax benefit at federal statutory rate	$472	$4,801	$31,585
State income tax benefit, net of federal impact	38	292	1,440
Change in Federal tax rate, net of state benefit (1)	(5,440)		
Loss on debt to equity conversion	(1,630)		
Effect of Sec. 382 Limitation	(29,803)		
Incentive stock options and restricted stock not deductible for tax purposes	964	-	(269)
Percentage depletion carryover	138	19	-
Prior year true up	1,076	534	171
Other	77		
Decrease in valuation allowance	(34,109)	(5,646)	(32,927)
Income tax benefit (expense)	$-	$-	$-

(1) The change in the Federal Tax rate was due to the passage of Public Law 115-97 (Tax Cuts and Jobs Act). This resulted in a provisional reduction of the Company's deferred tax assets before valuation analysis primarily due to a reduction in the US Statutory rate from 35% to 21%. We will continue to analyze the Tax Cuts and Jobs Act and future associated Treasury Regulations. This future analysis could potentially affect the measurement of deferred tax balances and give rise to new deferred tax amounts.

The components of deferred tax assets and liabilities as of December 31, 2017 and 2016 are as follows:

	2017	2016
Deferred tax assets:		
Net operating loss carryover (2)	$874	$26,739
Property and equipment	7,123	14,575
Percentage depletion and contribution carryovers (2)	1,872	2,512
Alternative minimum tax credit carryover (2)	785	706
Equity method investment and other	398	547
Deferred compensation liability	8	12
Asset retirement obligations	221	377
Stock-based compensation	83	(44)
Total deferred tax assets	11,364	45,424
Deferred tax liabilities:		
Property and equipment	-	-
Oil price risk derivatives	-	-
Other	(3)	(4)
Total deferred tax liabilities	(3)	(4)
Net deferred tax assets	11,361	45,420
Less valuation allowance	(11,361)	(45,420)
Net deferred tax asset	$-	$-

(2) On December 27, 2017, the Company paid down debt with common stock. This represented a 49.3% ownership change in the company. This combined with other equity events triggered Net Operation Loss limitations under I.R.C Section 382. As a result, the Company's Net Operating Loss carryforwards were significantly limited.

The Company has net operating loss carryovers (after limitations) as of December 31, 2017 of approximately $3,600,000 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 2036. In addition, the Company has alternative minimum tax credit carry-forwards of approximately $785,000 (subject to limitations) which are available to offset future federal income taxes over an indefinite period.

The statute of limitations is closed for the tax years through 2011. 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, 2017, 2016 and 2015, no adjustments were recognized for uncertain tax positions.

13. LOSS PER SHARE

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

	2017	2016	2015
Basic weighted average common shares outstanding	5,899,802	4,768,013	4,677,500
Dilutive stock options using treasury stock method	-	-	-
Diluted weighted average common shares outstanding	5,899,802	4,768,013	4,677,500

For the years ended December 31, 2017, 2016 and 2015, common stock equivalents excluded from the calculation of weighted average shares because they were antidilutive are as follows:

	2017	**2016**	**2015**
Stock options	389,687	390,525	390,525
Unvested shares of restricted common stock	5,555	24,832	16,667
Total	395,242	415,357	407,192

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, 2017, 2016 and 2015, three joint interest operators accounted for the following percentages of the Company's oil and gas sales:

Operator	2017	2016	2015
A	13 %	16 %	20 %
B	25 %	32 %	35 %
C	34 %	29 %	25 %

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.

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 adequate credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. 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 on December 31, 2016 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 2.01%. The Company remeasured the warrants as of December 31, 2017, using the same Monte Carlo model, using the following assumptions: a term expiring June 21, 2022, exercise price of $2.05, stock price of $1.50, average volatility rate of 90%, and a risk-free interest rate of 2.15%. As of December 31, 2017, the fair value of the warrants was $1,200,000, or $1.20 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.

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 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, 2017 and 2016 are as follows:

	December 31, 2017				December 31, 2016			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Marketable equity securitites:								
Sutter Gold Mining Company	$-	$8	$-	$8	$-	$ 16	$-	$16
Anfield Resources, Inc.	868	-	-	868	930	-	-	930
Total	$868	$8	$-	$876	$930	$ 16	$-	$946
Outstanding warrant liability	-	-	1,200	1,200	-	-	1,030	1,030
Crude oil price risk derivatives	-	161	-	161	-	-	-	-
Total	$-	$161	$1,200	$1,361	$-	$ -	$1,030	$1,030

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, 2017 and 2016:

	Assets Marketable Securities			Liabilities			
			Crude Oil	Crude Oil	Executive		
	Sutter	Anfield	Derivatives	Derivatives	Retirement	Warrants	
	(Level 2)	(Level 1)	(Level 2)	(Level 2)	(Level 3)	(Level 3)	Net
Fair value, December 31, 2015	13	238	1,634	-	(583)	-	1,302
Acquisition of investment	-	750	-	-	-	-	750
Issuance of warrants	-	-	-	-	-	1,240	1,240
Other comprehensive loss	3	-	-	-	-	-	3
Fair value adjustments included in net loss:	-						
Net unrealized gain on warrant valuation	-	-	-	-	-	(210)	(210)
Net unrealized loss on Anfield Shares	-	(58)	-	-	-	-	(58)
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
Total net losses included in:							
Acquisition of investment	-	777	-	-	-	-	777
Other comprehensive loss	(8)	-	-	-	-	-	(8)

Fair value adjustments included in net loss:				-			
Net unrealized loss on oil price risk derivatives	-	-	-	(26)	-	-	(26)
Net unrealized loss on warrant valuation	-	-	-	-	-	170	170
Net unrealized loss on Anfield Shares	-	(839)	-	-	-	-	(839)
Cash settlements paid	-	-	-	(135)	-	-	(135)
				-			
Fair value, December 31, 2017	$8	$ 868	$ -	(161)	$ -	$ 1,200	$1,915

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, 2017, 2016 and 2015 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Jane E. Trusty, PE. 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, 2017, 2016 and 2015:

	2017		2016		2015	
	Oil (bbls)	Gas **(mcfe)** [(1)]	Oil (bbls)	Gas **(mcfe)** [(1)]	Oil (bbls)	Gas **(mcfe)** [(1)]
Total proved reserves:						
Reserve quantities, beginning of year	657,280	1,379,163	1,615,180	2,477,930	4,119,736	3,211,245
Revisions of previous estimates	302,530	55,072	(795,459)	(584,494)	(2,377,364)	(206,912)
Discoveries and extensions	22,801	21,787	23,841	20,336	94,458	27,102
Sale of minerals in place	(194,667)	(118,944)	(53,853)	(57,258)	-	-
Production	(111,914)	(448,571)	(132,429)	(477,351)	(221,650)	(553,505)
Reserve quantities, end of year	676,030	888,507	657,280	1,379,163	1,615,180	2,477,930
Proved developed reserves, end of year	676,030	888,507	657,280	1,379,163	1,248,750	2,068,190

(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:

	2017	2016	2015
Oil per Bbl	$51.34	$42.75	$43.54
Gas per Mcfe [1]	$2.98	$2.48	$3.36

(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, 2017, 2016 and 2015:

	2017	2016	2015
Future cash inflows	$34,424	$27,769	$78,646
Future cash outflows:			
Production costs	(18,518)	(18,814)	(44,685)
Development costs	-	-	(8,050)
Income taxes	-	-	-
Future net cash flows	15,906	8,955	25,911
10% annual discount factor	(6,653)	(2,208)	(8,143)
Standardized measure of discounted future net cash flows	$9,253	$6,747	$17,768

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, 2017, 2016 and 2015 are as follows:

	2017	2016	2015
Standardized measure, beginning of year	$6,747	$17,768	$81,889
Sales of oil and gas, net of production costs	(3,143)	(3,102)	(2,944)
Net changes in prices and production costs	2,347	(9,248)	(96,586)
Changes in estimated future development costs	-	6,590	51,998
Extensions and discoveries	511	167	2,260
Sale of minerals in place	(1,049)	(78)	-
Revisions in previous quantity estimates	3,416	(6,791)	(27,693)
Previously estimated development costs incurred	-	-	-
Net changes in income taxes	-	-	3,306

Accretion of discount	675	1,777	8,189
Changes in timing and other	(251)	(336)	(2,651)
Standardized measure, end of year	$9,253	$6,747	$17,768

80

17. QUARTERLY FINANCIAL DATA (Unaudited)

The Company’s quarterly financial information for the two-year period ended December 31, 2017 is as follows:

	Year Ended December 31, 2016				Year Ended December 31, 2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Oil and gas sales	$1,066	$1,996	$1,867	$817	$1,747	$1,992	$1,538	$1,268
Operating expenses:								-
Impairment of oil and gas properties	(6,957)	(2,611)	-	-	-	-	-	-
Other (1)	(2,561)	(3,061)	(2,761)	276	(2,485)	(1,996)	(1,601)	(1,451)
Operating income (loss) (1)	$(8,452)	$(3,676)	$(894)	$1,093	$(738)	$(4)	$(63)	$(183)
Income (loss) from continuing operations (1)	$(8,275)	$(4,206)	$(265)	$1,074	$(740)	$(336)	$(382)	$98
Discontinued operations	(2,327)	(10)	-	(111)	-	-	-	-
Net income (loss)	$(10,602)	$(4,216)	$(265)	$963	$(740)	$(336)	$(382)	$983
Income (loss) per share - basic (1)(2):								
Continuing operations	$(1.76)	$(0.90)	$(0.06)	$0.23	$(0.13)	$(0.02)	$(0.06)	$0.02
Discontinued operations	(0.49)	(0.00)	-	-	-	-	-	-
Total	$(2.25)	$(0.90)	$(0.06)	$0.23	$(0.13)	$(0.02)	$(0.06)	$0.02
Income (loss) per								

share - diluted [1][2]:								
Continuing operations	$(1.76)	$(0.90)	$(0.06)	$0.23	$(0.13)	$(0.02)	$(0.06)	$0.02
Discontinued operations	(0.49)	(0.00)	-	-	-	-	-	-
Total	$(2.25)	$(0.90)	$(0.06)	$0.23	$(0.13)	$(0.02)	$(0.06)	$0.02
Weighted average shares outstanding:								
Basic	4,705,500	4,705,000	4,768,000	4,768,013	5,834,568	5,834,568	5,834,568	5,899,802
Diluted [1]	4,705,500	4,705,000	4,768,000	4,768,013	5,834,568	6,626,344	5,834,568	5,899,802

(1) Amounts have been restated from amounts reported in previous reports to retroactively present the impact of Discontinued Operations as discussed 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 2018 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 2018.

18. SUBSEQUENT EVENTS

On January 5, 2018 the Company entered into a common stock sales agreement with a financial institution pursuant to which we may sell from time to time, at our option, through the sales agent, shares of common stock representing an aggregate offering price of up to $2.5 million. Sales of the shares, if any, will be made in transactions that are deemed to be "at the market offerings" as defined in Rule 415 under the Securities Act of 1933, as amended.

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, 2017, 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.

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:

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 27, 2017 (incorporated by reference from Exhibit 3.1 to the Company's Form 10-Q filed May 19, 2017)
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)
4.2**	Standstill Agreement, dated September 28, 2017, by and between U.S. Energy Corp. and APEG Energy II, L.P. (incorporated by reference from Exhibit 10.2 to the Company's Form 8-K filed October 5, 2017)
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)**	APEG Energy II, L.P. – Fifth Amendment to Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed July 3, 2017)
10.1(f)**	BNP Paribas – Mortgage Agreement (incorporated by reference from Exhibit 10.2 to the Company's Form 8-K filed August 2, 2010)
10.1(g)**	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)
10.8(g)** †	Executive Employment Agreement – Ryan Smith (effective 5-18-17) (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed May 32, 2017)
10.8(h)* †	Agreement and Release by and among U.S. Energy Corp., Stephen Conrad, Thomas Bandy, Jerry Danni, James Fraser, and Leo Heath dated October 18, 2017
10.8(i)* †	Form of Option Agreement between U.S. Energy Corp. and its directors
10.8(j)* †	Form of Incentive Option Agreement between U.S. Energy Corp. and its executive officers
10.8(k)* †	Form of Indemnity Agreement between U.S. Energy Corp. and its directors and officers
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)
10.15**	Purchase and Sale Agreement, dated October 3, 2017, by and among U.S. Energy Corp., Energy One LLC and Statoil Oil and Gas LP (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed October 10, 2017)

10.16**	Exchange Agreement, dated September 28, 2017, by and among U.S. Energy Corp., Energy One LLC, and APEG Energy II, L.P. (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed October 5, 2017)
10.17**	Form of Common Stock Sales Agreement by and between U.S. Energy Corp. and Northland Securities Inc., dated January 5, 2018 (incorporated by reference from Exhibit 1.1 to the Company's Form 8-K filed January 5, 2018)
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)
16.1**	Letter of Hein & Associates LLP, regarding change in independent registered public accounting firm (incorporated by reference from Exhibit 16.1 to the Company's Form 8-K filed November 17, 2017)
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 Independent Registered Accounting Firm (Moss Adams LLP)
23.3*	Consent of Reserve Engineer (Jane E. Trusty, PE)
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
32.2*	Certification under Rule 13a-14(b) of Chief Financial Officer
99.1*	Reserve Report (Jane E. Trusty, PE)
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: March 28, 2018 By: */s/ David A. Veltri*
DAVID A. VELTRI, Chief Executive Officer

U.S. ENERGY CORP.

Date: March 28, 2018 By: */s/ Ryan L Smith*
RYAN L. SMITH, Chief Financial 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: March 28, 2018	By:	*/s/ David A. Veltri* DAVID A. VELTRI, Director, President and CEO (Principal Executive Officer)
Date: March 28, 2018	By:	*/s/ Ryan L. Smith* RYAN L. SMITH, Chief Financial Officer (Principal Accounting Officer)
Date: March 28, 2018	By:	*/s/ J. Weldon Chitwood* J. WELDON CHITWOOD, Director
Date: March 28, 2018	By:	*/s/ John G. Hoffman* JOHN G. HOFFMAN, Director
Date: March 28, 2018	By:	*/s/ Javier F. Pico* JAVIER F. PICO, Director