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, 2019

[ ] **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 000-06814

U.S. ENERGY CORP.

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.)
675 Bering, Suite 100, Houston, Texas	**77057**
(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	Trading Symbol(s)	Name of exchange on which registered
Common Stock, $0.01 par value	**USEG**	**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 every Interactive Data File required to be submitted 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 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer" "smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [ ]

Smaller reporting company [X] Emerging growth company [ ]

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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, 2019, was $6,166,682.

The Registrant had 1,404,817 shares of its $0.01 par value common stock outstanding as of March 20, 2020.

Part III incorporates information by reference from the registrant’s definitive proxy statement for the registrant’s 2020 Annual Meeting of Shareholders.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this Annual Report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (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 natural 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 natural gas approximating third-party estimates;
- anticipated changes in oil and natural 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 natural gas industry partners;
- when payout-based milestones or similar thresholds will be reached for the purposes of our agreements with our 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 natural gas properties;
- our ability to raise additional financing and acquire attractive oil and natural gas properties; and
- other plans and objectives for future operations.

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

- our ability to obtain sufficient cash flow from operations, borrowing and/or other sources to fully develop our undeveloped acreage positions;
- volatility in oil and natural 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 natural gas assets;
- the possibility that the oil and natural 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 natural gas in sufficient commercial quantities to provide a reasonable return on investment;
- future oil and natural gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;
- the ability to replace oil and natural 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 natural 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;
- disruptions resulting from unanticipated weather events, natural disasters, and public health crises and pandemics, such as the coronavirus, resulting in possible delays of drilling and completions and the interruption of anticipated production streams of hydrocarbons, which could impact expenses and revenues;
- litigation involving our former officers and directors, shareholders and third parties; 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 Natural Gas Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and natural 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 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or natural gas liquid.

Boed. Barrels of oil equivalent per day.

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 natural 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 Securities and Exchange Commission (“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 natural 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 natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural 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 natural gas producing properties in the continental United States. Our business activities are currently focused in South Texas and the Williston Basin in North Dakota.

We have historically explored for and produced oil and natural 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 natural gas wells. Before a well is drilled, the operator provides all oil and natural 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 natural gas production.

Office Location and Website

Our principal executive office is located at 675 Bering, Suite 100, Houston, Texas 77057. Our telephone number is (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 Natural Gas Operations

We currently participate in oil and natural gas projects as a non-operating working interest owner through exploration and development agreements with various oil and natural 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 natural gas properties or companies. Key attributes of our oil and natural gas properties include the following:

- Estimated proved reserves of 995,720 BOE (81% oil and 19% natural gas) as of December 31, 2019, with a standardized measure value of $10.3 million.
- As of December 31, 2019, our oil and natural gas leases covered 86,058 gross acres and 3,552 net acres.
- 107 gross (7.30 net) producing wells as of December 31, 2019.
- 397 BOE per day average net production for 2019.

PV-10 (defined in "Glossary of Oil and Natural Gas Terms") is a non-GAAP measure that is widely used in the oil and natural gas industry and is considered by institutional investors and professional analysts when comparing companies. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and natural gas properties in comparison with other companies. However, PV-10 data is not an alternative to the standardized measure of discounted future net cash flows, which is calculated under generally accepted accounting principles in the United States ("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, 2019, 2018 and 2017:

	2019	2018	2017
Standardized measure of discounted net cash flows	$ 10,348	$ 11,599	$ 9,253
Plus discounted impact of future income tax expense	1,724	1,425	-
PV-10	$ 12,072	$ 13,024	$ 9,253

Additional information about our standardized measure and the changes during each of the last two years is included in *Note 17-Unaudited Supplemental Oil and Natural Gas Information* to our consolidated financial statements included in Item 8 of this report on Form 10-K.

Activities with Operating Partners

We own 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 natural 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. However, consistent with industry practice with smaller independent oil and natural gas companies, we also utilize specialized consultants with local expertise, as needed.

Presented below is a description of significant oil and natural 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, LLC ("Zavanna") with an average working interest of approximately 16% and net revenue interests ranging from 2% to 31%. These properties operated by Zavanna currently comprise approximately 50% of the PV-10 related to our oil and natural gas reserves.

Texas (Gulf Coast)

Crimson Exploration Operating Inc. We have an interest in multiple wells with Crimson Exploration Operating Inc., which is the operator of the Leona River and Booth Tortuga prospects in which we currently hold a 29% working interest and a 22.2% net revenue interest. All of the leases are currently held by production and comprise approximately 9% of the PV-10 related to our oil and natural gas reserves.

Texas (South Texas)

CML Exploration, LLC. We have an interest in multiple producing wells with CML Exploration, LLC ("CML") in Dimmit and Zavala Counties, Texas with an average working interest of approximately 9% and an average net revenue interest of approximately 9%. These properties operated by CML currently comprise approximately 33% of the PV-10 related to our oil and natural gas reserves.

Environmental Laws and Regulations

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 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.

Comprehensive Environmental, Response, Compensation, and Liability Act ("CERCLA"). 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. 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 authorizes the Environmental Protection Agency ("EPA"), state environmental agencies, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. 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. 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.

Resource Conservation and Recovery Act ("RCRA"). RCRA is the principal federal statute governing the treatment, storage and disposal of hazardous and non-hazardous solid wastes. Analogous state laws also impose requirements associated with the management of such wastes. In the course of our operations, we and others generate petroleum hydrocarbon wastes, produced water and ordinary industrial wastes. RCRA currently exempts drilling fluids, produced waters, and other wastes associated with the exploration development, or production of crude oil, natural gas, or geothermal resources from regulation as hazardous wastes, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements. A similar exemption is contained in many of the state counterparts to RCRA.

Recently, following the filing of a lawsuit by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its non-hazardous waste (RCRA Subtitle D) criteria regulation for oil and natural gas wastes, the 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 was required to propose no later than March 15, 2019 a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or sign a determination that revision of the regulations is not necessary. The EPA missed the March 15, 2019 deadline, but in April 2019, the EPA determined that revisions to the federal regulations for the management of wastes associated with the exploration, development and production of crude oil, natural gas and geothermal energy under Subtitle D of RCRA were not necessary. This determination fulfilled EPA's obligations under the referenced 2016 Consent Decree.

The imposition of new federal requirements under RCRA Subtitle D can result in an increase of our operating expenses. Moreover, repeal or modifications of the exemption for certain oil and natural gas exploration and production wastes to be classified and regulated as non-hazardous 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.

The Endangered Species Act ("ESA"). The 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. The 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. Further, 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.

Air Emissions. The federal Clean Air Act (the "CAA") and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. Applicable to our business and operations, the CAA regulates emissions, discharges and controls with respect to 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 natural 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. 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.

In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions at specified sources. For example, under the EPA's 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 natural 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 require us to 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 CAA to a range within 65-70 ppb. On October 1, 2015, the 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 natural 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.

Permit 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 natural gas exploration and production operators to incur future capital and operating expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

Clean Water Act. The federal Water Pollution Control Act of 1972, or the Clean Water Act (the "CWA"), and analogous state laws, impose restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. 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 natural gas industry into certain regulated waters without an individual or general discharge permit issued by the EPA or an analogous state agency. 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. 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 regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of the CWA require appropriate containment berms and similar structures to help prevent the contamination of waters of the United States in the event of a petroleum hydrocarbon tank spill, rupture or leak.

The reach and scope of the CWA, and the determination of what water bodies and land areas are regulated as waters of the U.S., is the subject of various rules adopted by EPA and the U.S. Army Corps of Engineers (which we refer to as the WOTUS Rules), and on-going federal court litigation arising out of the rules and recent amendments. The WOTUS Rules, litigation over the rules, and the associated regulatory uncertainty, could impact our operations by subjecting new land and waters to regulation and increase our cost of operations. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.

Oil Pollution Act of 1990 ("OPA"). Federal regulations also require certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into surface waters. The OPA, and analogous state laws, contain numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. 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.

Safe Drinking Water Act ("SDWA"). The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended, and analogous state laws. The SDWA's Underground Injection Control ("UIC") 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 natural 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 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.

The Occupational Safety and Health Act ("OSHA"). 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.

Hydraulic Fracturing. 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. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and natural gas regulatory programs, but where these operations occur on federal or tribal lands they are subject to regulation by the U.S. Department of the Interior, Bureau of Land Management ("BLM"). 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 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. In addition to federal legislative and regulatory actions, some states and local governments have considered imposing, or have adopted, various conditions and restrictions on hydraulic fracturing operations. This includes states where we have interests. Louisiana and Texas, for example, have adopted 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.

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.

In May 2014, the EPA issued an advance notice of proposed rulemaking under the Toxic Substances Control Act to initiate a stakeholder process to request input on various aspects of obtaining information on chemical substances and mixtures used in hydraulic fracturing for oil and gas exploration and production. To date, no further action has been taken on the proposal.

National Environmental Policy Act (“NEPA”). Oil and natural gas exploration, development and production activities on federal lands, including tribal lands and lands administered by the BLM, are subject to NEPA. NEPA requires 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 an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. If we were to conduct any exploration and production activities on federal lands in the future, those activities may need to obtain governmental permits that are subject to the requirements of NEPA. This process has the potential to delay, limit or increase 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. In June 2016, the EPA published NSPS Subpart OOOOa standards that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. However, in April 2017, the EPA announced that it would review this methane rule for new, modified and reconstructed sources and initiated reconsideration proceedings to potentially revise or rescind portions of the rule. In June 2017, the EPA also proposed a two-year stay of certain requirements of the methane rule pending the reconsideration proceedings. The stay, however, was vacated by the D.C. Circuit Court of Appeals in July 2019. Accordingly, the June 2016 rule remains in effect, however, in September 2019, the EPA proposed amendments to the 2012 and 2016 NSPS for the oil and gas industry. The rule’s primary proposal would redefine the types of sources covered under the oil and gas industry to remove all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS, both for ozone-forming VOCs and GHGs. In addition, the primary proposal would rescind emission limits for methane from the remaining segments in the oil and gas industry – production and processing. As a secondary proposal, EPA would not redefine the types of sources covered under the oil and gas NSPS, but would still rescind the methane emission limits for the oil and gas industry. The rule would retain VOC standards for the production, processing, and transmission and storage segments of the industry. The comment period for this rulemaking ended on November 25, 2019 and EPA has not taken further action at this time.

Similarly, in November 2016, the BLM issued a final rule to reduce methane emissions by regulating venting, flaring, and leaks from oil and natural gas operations on federal and American Indian lands. California and New Mexico have challenged the rule in ongoing litigation. In addition, in April 2018, a coalition of states filed a lawsuit aiming to force the EPA to establish guidelines for limiting methane emissions from existing sources in the oil and natural gas section; that lawsuit is currently pending. These rules, should they remain in effect, or any other new methane emission standards imposed on the oil and natural 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 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.

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 natural 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.

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

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 natural 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.

Employees

As of December 31, 2019, we had 2 total and full-time employees and we utilized several consultants on an as-needed basis during 2019.

Forward Plan

In 2020 and beyond, we intend to seek additional opportunities in the oil and natural 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 existing companies, and the purchase of oil producing assets.

Business Strategy

Key elements of our business strategy 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 continuously evaluate strategic alternative opportunities that we believe will enhance shareholder value.

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 the Organization of the Petroleum Exporting Countries ("OPEC") and other oil exporting nations manage oil supply through export quotas. Additionally, natural gas prices continue to be under pressure due to concerns about 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 natural gas is a primary heating source.

Commodity prices have remained volatile over the past three years. While commodity prices generally improved in 2018 from 2017, commodity prices were generally lower in 2019, and oil prices have dropped significantly in March 2020. Currently, we do not have any commodity derivative contracts in place to mitigate the effect of lower commodity prices on our revenues. Lower oil and natural 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 natural 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.

Competition

The oil and natural gas industry is extremely 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 other companies explore for and produce oil and natural gas, many also engage in 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. Our competitors 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.

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 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 held 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 requires permits for drilling operations, drilling bonds and reports concerning operations and imposes 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, the flaring of natural gas, 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 that 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 that 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.

Litigation and Liquidity

APEG Energy II, L.P. (“APEG II”) and its general partner, APEG Energy II, GP (together with APEG II, “APEG”) are involved in litigation with us and our former Chief Executive Officer, David Veltri, as described below. As of March 20, APEG II holds approximately 41% of our outstanding common stock and was our secured lender prior to the maturity of our credit facility on July 30, 2019. The costs associated with the pending litigation were a significant use of our existing cash during 2019, but we believe that the expenditures are significantly behind us.

APEG II Litigation

On February 14, 2019, our Board of Directors (only one member of which remains on our Board following our 2019 Annual Meeting of Shareholders held on December 10, 2019) received a letter from APEG II urging us to establish a seven-person, independent board of directors, establish a corporate business plan and reduce our corporate general and administrative expenses. APEG II is our largest shareholder, owning approximately 41% of our outstanding common stock as of March 20, 2020 and was the secured lender under our credit facility, which we have repaid in full as discussed below.

On February 25, 2019, APEG II provided an access termination notice to our bank under its collateral documents, which resulted in all of the funds held in the collateral accounts, which totaled approximately $1.8 million, being wired to APEG II on March 1, 2019. On March 1, 2019, David Veltri, our former Chief Executive Officer and President, filed a lawsuit against APEG II in the Company’s name (the “Texas Litigation”). The Texas State Court granted the motion for a temporary restraining order (“TRO”) and ordered APEG to return immediately the approximate $1.8 million in cash previously wired to APEG II.

On March 4, 2019, APEG II filed an emergency motion with the U.S. District Court for the Southern District of Texas in order to remove the Texas Litigation from the State Court to the Federal District Court and to stay or modify the TRO. Following a hearing on March 4, 2019, the Texas Federal Court vacated the TRO and the Court ordered APEG to return our funds, less the outstanding balance due to APEG II under the credit facility of approximately $937 thousand, and we received back approximately $850 thousand.

On February 25, 2019, our Board held a meeting at which it voted to terminate Mr. Veltri for cause as Chief Executive Officer and President as a result of using Company funds outside of his authority and other reasons. Mr. Veltri, along with John Hoffman, a former Board member, called into question whether or not such action was properly taken at the Board meeting. On March 8, 2019, our Audit Committee intervened in the Texas Litigation by filing an emergency motion (the “AC Motion”). The AC Motion requested that the Texas Federal Court order that all of our funds and matters be placed under the control of our Chief Financial Officer and that control of these functions be removed from our former Chief Executive Officer.

On March 12, 2019, the Texas Federal Court granted the AC Motion, ordering that any disbursement made by us must be approved in writing by the Audit Committee in advance. Additionally, the Texas Federal Court ordered that our Chief Financial Officer must be appointed as the sole signatory on all of our bank accounts.

Litigation with Former Chief Executive Officer

In connection with the above described litigation with APEG II, APEG II then initiated a second lawsuit on March 18, 2019 as a shareholder derivative action in Colorado against Mr. Veltri, as a result of his refusal to recognize our Board’s decision to terminate him for cause (the “Colorado Litigation”). We were named as a nominal defendant in the Colorado Litigation. The APEG II complaint in the Colorado Litigation alleged that Mr. Veltri’s employment was terminated by our Board of Directors and sought an injunction and temporary restraining order against Mr. Veltri to prevent him from continuing to act as our Chief Executive Officer, President and Chairman.

On April 30, 2019, the Audit Committee took over the control of the defense of the Company, prosecution of its claims against APEG II, and filed third-party claims on behalf of the Company against Mr. Veltri and Mr. Hoffman, at the time a director of the Company, asserting that Mr. Veltri was responsible for any damages that APEG II claims, including attorneys’ fees, and that Mr. Veltri and Mr. Hoffman should be removed from our Board of Directors. On May 22, 2019, we and APEG II entered into a settlement agreement with Mr. Hoffman, pursuant to which Mr. Hoffman agreed to resign from the Board of Directors and committees thereof, and we agreed to pay up to $50,000 of his legal fees incurred. Further, we released Mr. Hoffman from any claims related to the Texas Litigation, APEG II released us from any claims that may have been caused by Mr. Hoffman, and Mr. Hoffman released us from any and all claims he may have had against the Company and its Board.

In the Colorado Litigation, the Colorado Federal Court granted interim preliminary injunctive relief to APEG II against Mr. Veltri, holding that Mr. Veltri, without authorization, continued to hold himself out to be, and continued to act as, as our President and Chief Executive Officer. Pursuant to the Order, Mr. Veltri was preliminarily enjoined from acting as, or holding himself out to be, our President and/or Chief Executive Officer, pending a trial on the merits. Ryan Smith, our Chief Financial Officer, was appointed temporary custodian of the Company with the charge to act as our Interim Chief Executive Officer.

On May 30, 2019, the Colorado Federal Court issued a subsequent order (the “Second Order”), appointing C. Randel Lewis as custodian of the Company pursuant to the Wyoming Business Corporation Act and to take over for Mr. Smith in acting as our Interim Chief Executive Officer and to serve on our Board of Directors as Chairman. The Second Order noted that the primary purpose of having Mr. Lewis serve as custodian was to resolve the Board deadlock regarding Mr. Veltri’s termination. Pursuant to the Second Order, Mr. Lewis, as custodian, was ordered to act in place of the Board to appoint one independent director to replace Mr. Hoffman. On June 13, 2019, Mr. Lewis appointed Catherine J. Boggs to serve as an independent director until the 2019 annual meeting of our shareholders, which was held on December 10, 2019. Following such annual meeting, our directors appointed Ryan Smith as our Chief Executive Officer to replace Mr. Lewis in that role. Following our annual meeting, the Colorado Federal Court also discharged Mr. Lewis from serving as our custodian, Interim Chief Executive Officer and as a member of our Board.

Both the Texas Litigation and the Colorado Litigation currently remain pending.

Audit Committee Investigation

Following the termination of Mr. Veltri on February 25, 2019, our independent auditors, Plante & Moran PLLC, informed the Audit Committee that the auditors had found irregularities in the submission and payment of expense reports with respect to our former Chief Executive Officer. Our Audit Committee engaged independent legal counsel, which subsequently engaged an independent accounting firm to conduct a forensic accounting investigation of our expense reporting system in relation to issues raised by our auditors regarding potential financial improprieties related to expense reports, including examining expense reports and third-party expenditures made by or through our former Chief Executive Officer or his staff. The investigation was expanded into a forensic investigation of the integrity of our computer-based record keeping after Mr. Veltri and Mr. Hoffman managed to reset the security codes to give them complete control of our books and records temporarily and exclude our other employees’, members of management’s, other officer’s and director’s ability to access those records during that period. The scope of the forensic accounting investigation covered the period from January 1, 2017 through March 31, 2019. Our Audit Committee took certain steps in response to the forensic accounting investigation. See “*Item 9A. Controls and Procedures—Changes in Internal Control Over Financial Reporting—Management’s Remediation Plan*.”

The forensic accounting investigation and our internal investigation also identified numerous expense items on Mr. Veltri’s expense reports that appeared to be personal in nature or lacked adequate documentation showing that such expense was for legitimate business purposes. These expense items totaled at least $81,014, of which $32,194 was incurred during the year ended December 31, 2017, $34,203 was incurred during the year ended December 31, 2018 and $14,617 was incurred during 2019 prior to Mr. Veltri’s termination. We reclassified the entire $81,014 reimbursed to Mr. Veltri as additional compensation and taxable income. In addition, we have accrued payroll taxes payable on the additional compensation.

The report also indicated that Mr. Veltri used the Company’s vendors for his own personal benefit. Mr. Veltri bypassed our accounts payable process by paying third-party vendors personally through expense reports and then approved his own expense reports, which limited the visibility of the payments and review by our accounting personnel.

Mr. Veltri also incurred $47,156 in third-party professional fees in connection with a potential transaction with a company controlled by a former Board member, which transaction and related expenses in evaluating the potential transaction were not approved by the Board. At December 31, 2018, the total amount of the fees was impaired and transferred to the full cost pool.

Mr. Veltri also entered into an agreement to acquire some oil and natural gas properties for which the Board authorized $250,000, which amount was fully refundable, subject to the funds being held in escrow pending the closing of the acquisition. Mr. Veltri wired the funds directly into the seller’s account, rather than escrowing such funds, and also paid the seller an additional $124,328, which amount was not authorized by the Board, as well as $40,578 for professional services. The transaction never closed, and the Company has received $200,000 refund of such funds from the seller.

Recent Developments

On March 1, 2020, we acquired all of the issued and outstanding equity interests of New Horizon Resources LLC (“New Horizon”), whose assets include acreage and operated producing properties in North Dakota (the “Properties”). The consideration paid at closing consisted of 59,498 shares of our common stock and $150,000 in cash (the “Acquisition”). The New Horizon Properties consist of approximately 1,300 net acres located primarily in McKenzie and Divide Counties, North Dakota, which are 100% held by production, average a 63% working interest and produced approximately 30 net Boepd (88% oil) for the six-month period ended December 31, 2019.

Item 1A. Risk Factors.

The following risk factors should be carefully considered in evaluating the information in this annual report on Form 10-K.

Risks Involving Our Business

The development of oil and natural 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 landowners;
- 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 natural 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.

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

For the three years ended December 31, 2019, oil prices have ranged from highs over $77 per barrel in 2018 to lows below $43 per barrel in 2017. 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 natural 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 natural 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 adjusted EBITDAX. Declines in the prices we receive for our oil and natural 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 natural 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.

Declines in oil and natural gas prices have and will materially adversely affect our revenues.

Our financial condition and results of operations depend in large part upon the prices obtainable for our oil and natural gas production and the costs of finding, acquiring, developing and producing reserves. As seen in recent years, prices for oil and natural gas are subject to extreme fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond tour control. These factors include worldwide political instability (especially in the Middle East and other oil producing regions), the foreign supply of oil and natural gas, the price of foreign imports, the level of drilling activity, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels, speculating activities in the commodities markets, and the overall economic environment. Our operations are substantially adversely impacted as oil prices decline. Lower prices dramatically affect our revenues. Further, drilling of new wells, development of our leases and acquisitions of new properties are also adversely affected and limited. As a result, our potential revenues as well as our proved reserves may substantially decrease from levels achieved during the period when oil prices were much higher. There can be no assurances as to the future prices of oil or natural gas. A substantial or extended decline in oil or natural gas prices would have a material adverse effect on our financial position, results of operations, quantities of oil and natural gas that may be economically produced, and access to capital. Oil and natural gas prices have historically been and are likely to continue to be volatile.

This volatility makes it difficult to estimate with precision the value of producing properties in acquisitions and to budget and project the return on exploration and development projects involving our oil and gas properties. In addition, unusually volatile prices often disrupt the market for oil and natural gas properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties.

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 ("WTI")). During 2019, our weighted average realized oil price in the Williston Basin was $51.92, which due to transportation costs was approximately $5.06 per barrel less than the average WTI spot price 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 oil and natural 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. 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.

Our former Chief Executive Officer, President and Chairman of the Board of Directors received expense reimbursements without adequate backup, and we paid certain vehicle expenses on behalf of an entity affiliated with John Hoffman, a former director, both of which may be deemed violations of Section 402 of the Sarbanes-Oxley Act of 2002 and/or other federal securities laws.

Our internal control testing identified inadequate supporting documentation and lack of adequate review for certain travel advances and expense reimbursements.

Following the termination of David Veltri, our former Chief Executive Officer, President and Chairman, our Audit Committee conducted a review of Company procedures, policies and practices, including travel expense advancements and reimbursements. Our Audit Committee retained independent counsel and an advisory firm with forensic accounting expertise to assist the Audit Committee in conducting the investigation. As part of the investigation, the Audit Committee reviewed our financial policies and procedures, including management expenses. The Audit Committee concluded that Mr. Veltri did not produce receipts with adequate detail for a portion of his reimbursed business expenses he received from 2017 to 2019.

In 2018 and 2019, we paid approximately $2,350 for vehicle expenses on behalf of an entity affiliated with Mr. Hoffman. While we were reimbursed for these expenses, it is possible that these payments by the Company on behalf of Mr. Hoffman could be deemed to be in violation of Section 402 of the Sarbanes-Oxley Act of 2002.

Section 402 of the Sarbanes Oxley Act of 2002 prohibits personal loans to a director or executive officer of a public company. If the SEC were to commence an investigation or institute proceedings to enforce a violation of this statute or other federal securities laws as a result of the reimbursement of expenses to Mr. Veltri or the payment of the vehicle expenses associated with an entity owned by an affiliated entity of Mr. Hoffman, we may become a party to litigation or proceedings over these matters, and the outcome of such litigation or proceedings (including criminal, civil or administrative sanctions or penalties by the SEC), alone or in addition to the costs of litigation, may materially and adversely affect our business. We are unable to predict the extent of our ultimate liability with respect to these payments.

We have identified material weaknesses in our internal control over financial reporting, and our management has concluded that our disclosure controls and procedures were not effective during 2017, 2018 and 2019. We cannot assure you that additional material weaknesses or significant deficiencies do not exist or that they will not occur in the future. If our internal control over financial reporting or our disclosure controls and procedures are not effective, we may not be able to accurately report our financial results or prevent fraud, which may cause investors to lose confidence in our reported financial information and may lead to a decline in our stock price.

Effective internal controls are necessary for us to provide reliable financial reports and effectively prevent fraud. We maintain a system of internal control over financial reporting, which is defined as a process designed by, or under the supervision of, our principal executive officer and principal financial officer, or persons performing similar functions, and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. 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 our financial statements will not be prevented or detected on a timely basis. Based on the results of management's assessment and evaluation of our internal controls, our principal executive officer and principal financial officer concluded that our internal control over financial reporting was not effective as of December 31, 2019 due to the material weakness described below.

As of December 31, 2019, we have identified the following material weaknesses:

- We had inadequate segregation of duties as a result of limited accounting staff and resources, which has impacted our ability to prevent or detect material errors in our consolidated financial statements and to properly implement new accounting standards.
- We had inadequate controls over physical and logical access to our information technology systems.

As a result, our management also concluded that our disclosure controls and procedures were not effective.as of December 31, 2019 such that the information relating to us required to be disclosed in the reports we file with the SEC (a) is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and (b) is accumulated and communicated to our management to allow timely decisions regarding required disclosures

If we do not successfully remediate the material weaknesses described above, or if other material weaknesses or other deficiencies arise in the future, we may be unable to accurately report our financial results on a timely basis or prevent fraud, which could cause our reported financial results to be materially misstated and require restatement which could result in the loss of investor confidence, delisting or cause the market price of our common stock to decline.

There are inherent limitations in all control systems and misstatements due to error or fraud may occur and not be detected.

The ongoing internal control provisions of Section 404 of the Sarbanes-Oxley Act of 2002 require us to identify material weaknesses in internal control over financial reporting, which is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with GAAP. Our management does not expect that our internal controls and disclosure controls, even once all material weaknesses and control deficiencies are remediated, will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of the Company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may and not be detected.

Pending litigation and other actions that may be threatened or taken against us could severely limit our liquidity.

We are currently involved in litigation with APEG II against us and our former Chief Executive Officer, as described in *Item 1. Business—Litigation and Liquidity—APEG II Litigation*. As of March 20, 2020, APEG II holds approximately 41% of our outstanding common stock and was our secured lender prior to the maturity on July 30, 2019 of our credit facility with APEG II. The costs associated with the pending litigation and other claims pending or threatened against us have been a significant use of our existing cash, and we have expended over $1.3 million in legal fees to date with respect to the pending actions. While we have historically funded all litigation costs out of operating cash flow, continued excessive legal fees associated with litigation could impair our liquidity profile and ability to fund significant drilling operations and participate in potential acquisitions in the future.

Non-consent provisions could result in penalties and loss of revenues from wells.

Our industry partners may elect to engage in drilling activities that we are unwilling or unable to participate in during 2020 and thereafter. 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 the participating parties 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 debt financing, sales of one or more producing or non-producing oil and natural gas assets and the issuance of shares of our common stock.

Unanticipated costs could require new capital that may not be available.

The oil and natural 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 natural 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 falling below projections, thus adversely impacting cash expected to be available for a continued work 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") to 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, we paid down debt under our credit facility with APEG II with shares of our common stock, which represented a 49.3% ownership change in the Company. As a result, our ability to use these NOLs and RBILS were significantly reduced in 2018 and 2019.

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

The oil and natural 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 natural 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 natural 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 natural 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 natural 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 natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and other midstream facilities. The 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, and 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 natural 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 intend to make acquisitions. However, suitable acquisition candidates may not 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 natural 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 natural 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 natural 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 natural 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 natural 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 natural 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 natural 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 qualifying as accounting hedges and asset retirement obligations, and unescalated oil and natural 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 natural gas cost center, which is the United States. During 2019 and 2018, our capitalized costs for oil and natural gas properties did not exceed the ceiling and, therefore, we did not record an aggregate ceiling test write-down. 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, 2019, we used an average price applicable to our properties of $55.69 per barrel for oil and $2.58 per Mcfe for natural gas, based on average prices per barrel of oil and per Mcfe of natural gas at the first day of each month of the 12-month period prior to the end of the reporting period, to compute the future cash flows of each of the producing properties at that date.

As of March 20, 2020, the WTI spot price for crude oil was $23.64 and the 12-month strip price was $28.44. To determine the extent of these price reductions on the realizability of the Company's oil and gas properties, the Company reran the year end reserves using 50% of the average crude price used in the original ceiling test calculation, or $27.85, as further adjusted for differentials, and determined that by using that price the Company would have incurred a ceiling test write-down of approximately $1.7 million.

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 approximately $3.7 million as of December 31, 2019. 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 serve as the operator for most of our oil and natural 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 natural 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.

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 natural 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 operate most of 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 natural 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 natural 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 natural gas reserves is a complex process and not an exact science. 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 natural 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, 2019, 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.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. The timing and success of the production and the expenses related to the development of oil and natural 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 natural gas industry in general are subject.

The use of derivative arrangements in oil and natural 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 and natural gas 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") 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 creation of position limits for certain derivatives transaction, as well as requiring certain transactions 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"), the SEC and other regulators to promulgate rules and regulations implementing the Dodd-Frank Act.

The CFTC has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin, clearing and trade execution; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. Also, it is possible that under recently adopted margin rules, some registered swap dealers may require us to post initial and variation margins in connection with certain swaps not subject to central clearing.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter and reduce our ability to monetize or restructure our existing commodity derivative contracts. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

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 natural 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 natural 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 natural gas properties to obtain and maintain liability insurance for our working interest in our oil and natural 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 natural 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"* in *"Item 1 – Business"*.

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 natural 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:

- 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 keep informed of actions pertaining to future regulatory requirements that might be imposed in order 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.

See "*Environmental Laws and Regulations*" in Item 1 – Business in this Form 10-K for a discussion of the major environmental, health and safety laws and regulations that relate to our business. We believe, but cannot be certain, that we are in material compliance with these laws and regulations. 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.

We are dependent upon information technology systems, which are subject to disruption, damage, failure and risks associated with implementation and integration.

We are dependent upon information technology systems in the conduct of our operations. Our information technology systems are subject to disruption, damage or failure from a variety of sources, including, without limitation, computer viruses, security breaches, cyberattacks, natural disasters and defects in design. Cybersecurity incidents, in particular, are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and other electronic security breaches that could lead to disruptions in systems, unauthorized release of confidential or otherwise protected information and the corruption of data.

Various measures have been implemented to manage our risks related to information technology systems and network disruptions. However, given the unpredictability of the timing, nature and scope of information technology disruptions, we could potentially be subject to operational delays, the compromising of confidential or otherwise protected information, destruction or corruption of data, security breaches, other manipulation or improper use of our systems and networks or financial losses from remedial actions, any of which could have a material adverse effect on our cash flows, competitive position, financial condition or results of operations.

Permitting requirements could delay our ability to start or continue our operations.

Oil and natural 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 or recycling 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 natural 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 natural 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 natural gas industry can fluctuate significantly, often in correlation with oil and natural 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 natural 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 natural 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 management team has experience in dealing with the acquisition and financing of oil and natural gas properties. We rely extensively on third-party consultants for legal, engineering, geophysical and geological advice in oil and natural gas matters. The loss of key personnel 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 1.33 shares of our common stock (the "Conversion Rate") for an aggregate of 66,667 shares. This Conversion Rate reflects the effect of the reverse stock split described in this *"Item 1A. Risk Factors"* (the "Reverse Stock Split"). 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 79,334 shares after taking into account the effect of the Reverse Stock Split. 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 shareholders beneficially owns a significant portion of our common stock, and its interests may conflict with those of our other shareholders.

As of March 20, 2020, APEG II beneficially owns 581,927 shares (as adjusted for the Reverse Stock Split), or approximately 41%, of our outstanding common stock. As a result, APEG II is able to exercise significant influence over matters requiring shareholder 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 II 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 shareholders. See "*Pending litigation and other actions that may be threatened or taken against us could severely limited our liquidity"* in this *Item1A. Risk Factors* and the discussion of this litigation in *Item 1. Business—Litigation and Liquidity —APEG II Litigation.*

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. Recently, we privately issued 59,498 shares of our common stock in the New Horizon Acquisition. 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, we are prohibited from paying dividends on our common stock without the approval of the holders of the Series A Preferred. 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. During the two years ended December 31, 2019, our common stock has traded as high as $17.60 per share and as low as $3.00 per share, as adjusted for the Reverse Stock Split. 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 natural 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 natural gas prices have declined significantly. These fluctuations have particularly affected the market prices of securities of oil and natural gas companies like ours.

We effected a reverse stock split which may adversely impact the market price of our common stock.

Effective January 6, 2020, we completed a reverse stock split of our outstanding common stock at a ratio of one-for-ten shares (the "Reverse Stock Split"). The effect of the Reverse Stock Split upon the future market price of our common stock cannot be predicted with certainty. Accordingly, it is possible that the market price of our common stock could decline more than would occur in the absence of the Reverse Stock Split.

The Reverse Stock Split may decrease the liquidity of the shares of our common stock and the resulting market price of our common stock may not attract or satisfy the investing requirements of new investors, including institutional investors.

The liquidity of the shares of our common stock may be affected adversely by the Reverse Stock Split given the reduced number of shares outstanding following the Reverse Stock Split. Additionally, the Reverse Stock Split may increase the number of shareholders who own odd lots (less than 100 shares) of our common stock, creating the potential for such shareholders to experience an increase in the cost of selling their shares and greater difficulty effecting such sales. Moreover, there can be no assurance that the Reverse stock Split will result in a share price that will attract new investors, including institutional investors, and there can be no assurance that the market price of our common stock will satisfy the investing requirements of these investors. Consequently, the trading liquidity of our common stock may not necessarily improve as a result of the Reverse Stock Split.

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, our common stock must maintain a minimum bid price of $1.00 as set forth in NASDAQ Marketplace Rule 5550(a)(2) (the "Minimum Price Requirement"). If the closing bid price of our common stock is below $1.00 for 30 consecutive trading days, then the closing bid price of our 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. Previously, we were not in compliance with the Minimum Price Requirement but regained compliance following the Reverse Stock Split. We cannot guarantee that we will be able to remain in compliance with the Minimum Price Requirement in the future 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 the NASDAQ Capital Market could adversely impact the liquidity and value of our common stock.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

Oil and Natural Gas Interests

We do not have in-house geophysical or reserve engineering expertise. We therefore primarily rely on the operators of our producing wells to provide production data to our independent reserve engineers. Reserve estimates are based on average prices per barrel of oil and per Mcfe 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, 2019, 2018 and 2017 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:

	Average Price During		
	2019	2018	2017
Oil (per Bbl)	$ 55.69	$ 65.56	$ 51.34
Gas (per Mcfe)	$ 2.58	$ 3.10	$ 2.98

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

	As of December 31,								
	2019 (1)			2018 (1)			2017 (1)		
	Oil (Bbl)	Natural Gas (Mcf)	Total (BOE)	Oil (Bbl)	Natural Gas (Mcf)	Total (BOE)	Oil (Bbl)	Natural Gas (Mcf)	Total (BOE)
Proved developed	807,510	1,129,260	995,720	751,260	738,000	874,260	676,030	888,507	824,115
Proved undeveloped	-	-	-	-	-	-	-	-	-
Total proved reserves	807,510	1,129,260	995,720	751,260	738,000	874,260	676,030	888,507	824,115

(1) Our reserve estimates as of December 31, 2019 are based on a reserve report prepared by Don Jacks, PE. Mr. Jacks is licensed independent petroleum engineer in the State of Texas since 1992. Our reserve estimates as of December 31, 2018 and 2017 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 Mr. Jacks and Ms. Trusty were based upon their 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 Mr. Jacks' report is filed as an exhibit to this annual report on Form 10-K.

As of December 31, 2019, our proved reserves totaled 995,720 BOE, of which 100% were classified as proved developed. On a BOE basis, approximately 81% of the total proved developed reserves are derived from 807,510 Bbls of oil and 19% is derived from 1,129,260 Mcfe of natural gas and NGLs. See the "Glossary of Oil and Natural 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.

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 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 Don Jacks, PE. Mr. Jacks 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 Mr. Jacks can prepare his independent reserve estimates and final report.

Proved Undeveloped Reserves. As of December 31, 2019, 2018 and 2017, we did not book any proved undeveloped ("PUD") reserves due to the uncertainty regarding the availability of capital that would be required to develop the PUD reserves.

Oil and Natural 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 natural gas for the years ended December 31, 2019, 2018 and 2017.

	2019	2018	2017
Production Volume			
Oil (Bbls)	110,090	75,003	111,914
Natural gas (Mcfe)	209,518	286,692	448,571
BOE	145,010	122,785	186,676
Daily Average Production Volume			
Oil (Bbls per day)	302	205	307
Natural gas (Mcfe per day)	574	785	1,229
BOE per day	397	336	511
Net prices realized			
Oil per Bbl	$ 55.85	$ 61.45	$ 45.16
Natural gas per Mcfe	2.03	3.24	3.32
Oil and natural gas per BOE	45.33	45.11	35.06
Operating Expenses per BOE			
Lease operating expenses and production taxes	$ 15.70	$ 18.65	$ 18.22
Depletion, depreciation and amortization	4.79	3.20	3.86

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, 2019, 2018 and 2017

	2019			2018			2017		
	Oil (Bbl)	**Natural Gas (Mcfe)**	**Total (BOE)**	**Oil (Bbl)**	**Natural Gas (Mcfe)**	**Total (BOE)**	**Oil (Bbl)**	**Natural Gas (Mcfe)**	**Total (BOE)**
Williston Basin (North Dakota)	47,170	82,620	60,940	48,884	91,546	64,142	90,534	149,944	111,974
Eagle Ford/ Buda/Austin Chalk/Georgetown (South Texas)	62,920	126,898	84,070	26,119	88,260	40,829	21,380	132,055	43,390
Gulf Coast (Louisiana)	-	-	-	-	106,886	17,814	-	187,876	31,312
Total	110,090	209,518	145,010	75,003	286,692	122,785	111,914	448,571	186,676

Drilling and Other Exploratory and Development Activities. The following table sets forth information with respect to development and exploratory activity on wells in which we own an interest during the periods ended December 31, 2019, 2018 and 2017.

	2019		2018		2017	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Development wells:						
Productive	-	-	-	-	-	-
Non-productive	-	-	-	-	-	-
Sub-total	-	-	-	-	-	-
Exploratory wells:						
Productive	4	0.16	1	0.30	1	0.06
Non-productive	-	-	-	-	-	-
Sub-total	4	0.16	1	0.30	1	0.06
Total	4	0.16	1	0.30	1	0.06

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 natural 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.

Present Activities. From January 1, 2020 through March 20, 2020 we have not participated in any drilling activities, nor are we in the process of participating in any drilling activities.

Oil and Natural Gas Properties, Wells, Operations and Acreage. The following table summarizes information about our gross and net productive wells as of December 31, 2019.

	Gross Producing Wells			**Net Producing Wells**			**Average Working Interest**		
	Oil	**Gas**	**Total**	**Oil**	**Gas**	**Total**	**Oil**	**Gas**	**Total**
North Dakota	91	-	91	3.75	-	3.75	3.75%	-%	3.75%
Texas	35	-	35	8.83	-	8.83	25.23%	-%	25.23%
Total	126	-	126	12.58	-	12.58	9.98%	-%	9.98%

Wells are classified as oil or natural gas wells according to the predominant production stream.

Acreage. The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2019.

	Developed		**Undeveloped**		**Total**	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**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	4,804	603	-	-	4,804	603
Big Wells Prospect	240	36	3,242	397	3,482	433
Carrizo Creek and South McKnight Prospects	-	-	823	52	2,634	339
Total	81,993	3,103	4,065	449	86,058	3,552

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, 2019, all of our acreage in North Dakota and Texas is held by production.

Real Estate

We own a 14-acre tract in Riverton, Wyoming with a two-story, 30,400 square foot office building, which served as our corporate headquarters until we relocated to our prior headquarters in Denver, Colorado in 2015. Currently, the building is rented to non-affiliates and government agencies. We have plans to market the building and land for sale in the second quarter of 2020.

In addition, we own three city lots covering 13.84 acres adjacent to our office building in Riverton, Wyoming. We also have plans to market these properties for sale in the second quarter of 2020. 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.

Marketing, Major Customers and Delivery Commitments

Markets for oil and natural 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, 2019.

Competition

The oil and natural gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and natural gas. Our competitors principally consist of major and intermediate-sized integrated oil and natural gas companies, independent oil and natural gas companies and individual producers and operators. Specifically, 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.

See *Item 1. Business.—Litigation and Liquidity—APEG II Litigation* and *–Litigation with Former Chief Executive Officer* for a description of certain legal proceedings pending at December 31, 2019. We did not otherwise have any material legal proceedings pending at December 31, 2019, or resolved or otherwise terminated during the quarter ended December 31, 2019.

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 NASDAQ Capital Market under the symbol "USEG". Prices are reported on a "last sale" basis. The prices have been adjusted to reflect a one share-for-ten shares reverse stock split which was effective on January 6, 2020 (the "Reverse Stock Split"):

	Low	High
Year ended December 31, 2019:		
First quarter	$ 7.20	$ 9.20
Second quarter	3.00	7.80
Third quarter	4.00	6.60
Fourth quarter	3.00	5.10
Year ended December 31, 2018:		
First quarter	$ 11.20	$ 17.60
Second quarter	10.70	14.50
Third quarter	8.20	14.00
Fourth quarter	6.90	10.30

As of March 20, 2020, the closing sales price of our common stock was $2.51per share.

In order for us to maintain the listing of our shares of common stock on the NASDAQ Capital Market, our common stock must maintain a minimum bid price of $1.00 as set forth in NASDAQ Marketplace Rule 5550(a)(2). (the "Minimum Price Requirement"). If the closing bid price of our 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. Previously, we were not in compliance with the Minimum Price Requirement but regained compliance following the Reverse Stock Split. We cannot guarantee that we will be able to remain in compliance with the Minimum Price Requirement in the future 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 the NASDAQ Capital Market could adversely impact the liquidity and value of our common stock.

Holders

As of March 20, 2020, we had 1,404,817 shares of common stock issued and outstanding.

Dividends

We did not declare or pay any cash dividends on common stock during fiscal years 2019 and 2018 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 Series A Preferred. See *Note 7-Disposition of Mining Segment* and *Note 12-Preferred Stock* to the Consolidated Financial Statements herein and *Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments.*

Share Repurchases

During the three months ended December 31, 2019, the Company did not repurchase any shares of its common stock.

Item 6. Selected Financial Data

This Item is not required for smaller reporting companies.

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 annual report on Form 10-K for important information about these types of statements. Additionally, please refer to the *Glossary of Oil and Natural Gas Terms* of this annual report on Form 10-K for oil and natural gas industry terminology used herein.

Recent Developments

On March 1, 2020, we acquired all of the issued and outstanding equity interests of New Horizon Resources LLC (“New Horizon”), whose assets include acreage and operated producing properties in North Dakota (the “Properties”). The consideration paid at closing consisted of 59,498 shares of our common stock and $150,000 in cash. The New Horizon Properties consist of approximately 1,300 net acres located primarily in McKenzie and Divide Counties, North Dakota, which are 100% held by production, average a 63% working interest and produced approximately 30 net Boepd (88% oil) for the six-month period ended December 31, 2019.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with 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 annual 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 Natural Gas Reserve Estimates. Our estimates of proved reserves are based on quantities of oil and natural 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 natural 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 Natural Gas Properties. We follow the full cost method in accounting for our oil and natural gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and natural 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 natural 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 natural 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 natural 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 natural 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, an impairment is recognized.

Derivative Instruments. We have used derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk underlying our oil and natural 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 natural 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 our Chief Executive

Officer and Chief Financial Officer as the representative who is authorized to execute trades.

Joint Interest Operations. We do not serve as operator for any of our oil and natural 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 recognize revenue in accordance with FASB ASC Topic 606-*Revenue from Contracts with Customers*, which we adopted effective January 1, 2018, using the modified retrospective approach. See *Note 2- Revenue Recognition* to the Consolidated Financial Statements herein for more information on our adoption of this new accounting standard.

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.

Warrant Liability. In connection with a private placement of common shares in December 2016, we concurrently sold to the purchasers warrants to purchase 100,000 shares of common stock. The exercise price and the number of shares issuable upon exercise of the warrants is subject to adjustment in the event of any stock dividends and splits, reverse stock splits, recapitalization, reorganization or similar transaction, as described in the warrants. The warrants are also subject to "down-round" anti-dilution in the event we issue additional common stock or common stock equivalents at a price per share less than the exercise price in effect. We have classified the warrants as liabilities due to provisions in the warrant agreement that precluded equity classification, including an option of the holder to receive the calculated fair value of the warrant from the Company in cash in the event of a "Fundamental Transaction," as defined in the warrant agreement. Changes in fair value are reported each period in the consolidated statements of operations.

Preferred Stock. We have excluded our Series A Convertible Preferred Stock from stockholders' equity due to a redemption feature whereby the holders of the preferred stock have the option to redeem their shares in the event of a change of control, which is outside of our control. See *Note 12- Preferred Stock* to the Consolidated Financial Statements herein for more information related to the Series A Convertible Preferred Stock.

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 annual 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, 2019 and 2018

During the year ended December 31, 2019, we recorded a net loss of $0.6 million as compared to a net loss of $1.0 million for the year ended December 31, 2018. In the following sections we discuss our revenue, operating expenses, and non-operating income for the year ended December 31, 2019 compared to the year ended December 31, 2018.

Revenue. Presented below is a comparison of our oil and natural gas sales, production quantities and average sales prices for the years ended December 31, 2019 and 2018 (dollars in thousands, except average sales prices):

			Change	
	2019	2018	Amount	Percent
Revenue:				
Oil	$ 6,149	$ 4,609	$ 1,540	33%
Gas	424	930	(506)	-54%
Total	$ 6,573	5,539	$ 1,034	19%
Production quantities:				
Oil (Bbls)	110,090	75,003	35,087	47%
Gas (Mcfe)	209,518	286,692	(77,174)	-27%
BOE	145,010	122,785	22,225	18%

Average sales prices:				
Oil (Bbls)	$ 55.85	$ 61.45	$ (5.60)	-9%
Gas (Mcfe)	2.03	3.24	(1.21)	-38%
BOE	45.33	45.11	0.22	0.5%

The increase in our oil sales of $1.5 million for the year ended December 31, 2019 resulted from a 47% increase in production quantities, which was partially offset by a 9% decrease in the average sales price received during 2019 compared to 2018. The increase in our production quantities for the year ended December 31, 2019 was primarily attributable to production from the development of our South Texas acreage. During 2019, the average differential between WTI quoted prices for crude oil and the prices we realize for sales in the Williston Basin was approximately $5.06 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, 2019, we produced 145,010 BOE, or an average of 397 BOE per day, as compared to 122,785 BOE or 336 BOE per day in 2018. Production for our Williston Basin properties decreased by 3,202 BOE during 2019, which is a 5% reduction compared to 2018. This decrease is primarily due to normal production declines. Production from our Eagle Ford, Buda and Georgetown properties in South Texas increased by 43,241 BOE during 2019, a 106% increase compared to 2018. This increase was attributable to the production from our South Texas drilling activity in late 2018 and during 2019.

Oil and Natural Gas Production Costs. Presented below is a comparison of our oil and natural gas production costs for the years ended December 31, 2019 and 2018 (dollars in thousands):

	2019	2018	Change Amount	Change Percent
Lease operating expenses	$ 1,848	$ 1,898	$ (50)	-3%
Production taxes	429	392	37	9%
Total	$ 2,277	$ 2,290	$ (13)	-1%

For the year ended December 31, 2019, lease operating expense decreased by $50 thousand or 3%. For the year ended December 31, 2019 due to reduced field activity and a reduction in workover expense. Production taxes increased by $37 thousand or 9% compared to 2018. The increase in production taxes is primarily a result of increased revenue from oil and natural gas sales as a result of the production increases in our South Texas properties.

Depreciation, Depletion and Amortization. Our DD&A rate for the year ended December 31, 2019 was $4.78 per BOE compared to $3.20 per BOE for 2018. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Impairment of Oil and Natural Gas Properties. During the years ended December 31, 2019 and 2018, we did not record any impairment charges related to our oil and natural gas properties. Our quarterly reserve reports are prepared based on the first-of-the-month, trailing 12-month average for benchmark oil and natural 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, 2019 and 2018 (dollars in thousands):

	2019	2018	Change Amount	Change Percent
Compensation and benefits, including directors	$ 1,146	$ 1,453	$ (307)	-21%
Stock-based compensation	41	636	(595)	-94%
Professional fees, insurance and other	3,178	1,540	1,638	106%
Bad debt expense	28	374	(346)	-93%
Total	$ 4,393	$ 4,003	$ 390	9%

General and administrative expenses increased by $0.4 million, or 9%, for the year ended December 31, 2019 compared to the year ended December 31, 2018. This increase was primarily attributable to an increase of $1.6 million related to professional fees. During 2019, we incurred $1.3 million in incremental legal and accounting fees as a result of the APEG II litigation and the forensic accounting review. We believe the expenditures related to the APEG litigation are substantially behind us and expect a significant reduction in professional fees in 2020. Partially offsetting the increase in professional fees were decreases in compensation and benefits and stock-based compensation as a result of reduced headcount and the lack of the payment of a stock bonus for the year ended December 31, 2019. In addition, bad debt expense decreased $0.3 million. Bad debt expense in 2018 was attributable to the write-off of a deposit for an abandoned acquisition prospect, for which return of the deposit was uncertain, however, during 2019 we recovered $150 thousand of the deposit and as of March 20, 2020 we have received a total of $200 thousand. We have recorded the recovery of the deposit in non-operating income. Bad debt expense in 2019 relates to the write-off of a receivable from a joint interest operator in bankruptcy.

Non-Operating Income (Expense). Presented below is a comparison of our non-operating income (expense) for the years ended December 31, 2019 and 2018 (dollars in thousands):

			Change	
	2019	**2018**	**Amount**	**Percent**
Realized loss on commodity price risk derivatives	$ -	$ (283)	$ 283	100%
Unrealized gain on commodity price risk derivatives	-	161	(161)	100%
Recovery of deposit	200	-	200	100%
Loss on marketable equity securities	(230)	(339)	109	-32%
Rental and other expense	(70)	(114)	44	-39%
Gain on warrant revaluation	351	775	(424)	-55%
Interest expense, net	(11)	(93)	82	-88%
Total other income	$ 240	$ 107	$ 133	124%

At December 31, 2019 and 2018 we did not have any outstanding commodity derivative contracts. For the year ended December 31, 2018, we recognized unrealized gains on commodity price risk derivatives of $0.2 million and realized losses of $0.3 million.

During the year ended December 31, 2019, we recognized $0.2 million on the recovery of a transaction deposit for an abandoned acquisition prospect, which was written-off in 2018.

During the year ended December 31, 2019 and 2018, we recognized unrealized losses on marketable equity securities of $0.2 million and $0.3 million, respectively primarily due to a decline in the value of our investment in marketable securities of Anfield Energy.

We recognized rental and other expense of $0.1 million for each of the years ended December 31, 2019 and 2018 related to the operation of our building in Riverton, Wyoming.

During the years ended December 31, 2019 and 2018, we recognized gains on the revaluation of our outstanding warrants of $0.4 million and $0.8 million, respectively, primarily as a result of the decline in value of our common stock.

Interest expense, net decreased by $82 thousand for the year ended December 31, 2019 compared to 2018 due to the repayment of $937 thousand outstanding on the credit agreement in March 2019.

Non-GAAP Financial Measures – Adjusted EBITDAX

Adjusted EBITDAX represents income (loss) from continuing operations as further modified to eliminate impairments, depreciation, depletion, accretion and amortization, stock-based compensation expense, loss (gain) on marketable equity securities, unrealized derivative (gains) and losses, interest expense, net 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 natural 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.

The following table provides reconciliations of net loss to adjusted EBITDAX for the years ended December 31, 2019 and 2018, in thousands:

	2019	2018
Net loss (GAAP)	$ (550)	$ (1,040)
Depreciation, depletion, accretion and amortization	693	393
Loss on marketable equity securities	229	339
Stock-based compensation expense	41	636
Unrealized derivative gain	-	(161)
Change in fair value of warrants	(352)	(775)
Interest expense, net	11	93
Adjusted EBITDAX (Non-GAAP)	$ 72	$ (515)

Liquidity and Capital Resources

In our Annual Report on Form 10-K for the year ended December 31, 2018 we reported that there was substantial doubt regarding our ability to fund operations for the next twelve months and continue as a going concern. The substantial doubt was primarily related to uncertainty regarding continuing expenditures in the APEG II litigation. Although the litigation remains pending, we believe that the expenditures related to the litigation are substantially behind us. During 2019, we took many steps to preserve liquidity including reducing the use of third-party contractors, cutting corporate overhead and eliminating other general and administrative costs. Additionally, in March 2020, there has been a significant decline in commodity prices. While we expect to experience a decrease in our oil and natural gas revenue, we believe that our existing cash and capital resources and our low overhead has alleviated the substantial doubt regarding our ability to continue as a going concern and we expect we will be able to fund operations for the next twelve months.

The following table sets forth certain measures about our liquidity as of December 31, 2019 and 2018, in thousands:

	2019	**2018**	**Change**
Cash and equivalents	$ 1,532	$ 2,340	$ (808)
Working capital surplus [(1)]	1,470	2,018	(548)
Total assets	13,467	14,778	(1,392)
Outstanding debt under credit facility	-	937	(937)
Borrowing base under credit facility	-	6,000	(6,000)
Total shareholders' equity	9,210	9,719	(509)
Select Ratios:			
Current ratio [(2)]	2.20 to 1.00	2.21 to 1.00	
Debt to equity ratio [(3)]	N/A	0.10 to 1.00	

(1) Working capital is computed by subtracting total current liabilities from total current assets.
(2) The current ratio is computed by dividing total current assets by total current liabilities.
(3) The debt to equity ratio is computed by dividing total debt by total shareholders' equity.

As of December 31, 2019, we had a working capital surplus of $1.5 million compared to a working capital surplus of $2.0 million as of December 31, 2018, a decrease of $0.5 million. This decrease was primarily attributable to additional legal and professional expenses as a result of the litigation with APEG II, which was partially offset by an increase in oil and natural gas revenue as a result of production increases in our South Texas properties.

Our sole source of debt financing was a revolving credit facility with APEG II, which we repaid in full in March 2019 and the credit facility matured on July 30, 2019. The borrowing base was $6.0 million as of December 31, 2018. As of December 31, 2018, outstanding borrowings were $0.9 million and we had borrowing availability of $5.1 million. As of December 31, 2018, we were in compliance with all financial covenants associated with the credit facility. APEG II was the secured lender under the credit facility and is currently involved in litigation with us, as described in *Item 1. Business—Litigation and Liquidity—APEG II Litigation*. As described above, the costs associated with the pending litigation were a significant use of our existing cash during 2019, but we believe the expenditures are significantly behind us.

As of December 31, 2019, we had cash and cash equivalents of $1.5 million and accounts payable and accrued liabilities of $1.0 million. As of March 20, 2020, we had cash and cash equivalents of $1.4 million and accounts payable and accrued liabilities of approximately $0.7 million.. As of March 20, 2020, we have incurred approximately $1.3 million for litigation and the forensic accounting investigation.

In early March 2020, the NYMEX WTI crude oil price decreased significantly. Currently, we do not have any commodity derivative contracts in place to mitigate the effect of lower commodity prices on our revenues. Lower oil and natural gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce.

Lower crude prices could also affect the realizability of our oil and gas properties. In the calculation of the ceiling test for the year ended December 31, 2019, we used $55.69 per barrel for oil and $2.58 per mcf for natural gas (as further adjusted for differentials related to property, specific gravity, quality, local markets and distance from markets) to compute the future cash flows of our producing properties. The discount factor used was 10%. As of March 20, 2020, the WTI spot price for crude oil was $23.64 and the 12-month strip price was $28.44. To determine the extent of these price reductions on the realizability of our oil and gas properties, we reran the year end reserves using 50% of the average crude price used in the original ceiling test calculation, or $27.85, as further adjusted for differentials, and determined that by using that price the Company would have incurred a ceiling test write-down of approximately $1.7 million.

In February 2020, we began a process to sell our building and land in Riverton, Wyoming. An independent appraisal prepared as of January 31, 2020, valued the building and land at $3.8 million. We are working with a large national commercial real estate firm to market the property which we expect to begin in the second fiscal quarter of 2020. We cannot be certain that we will be able to complete the sale of the property in 2020 at or near the appraised value, or at all.

If we have needs for financing in 2020, alternatives that we will consider in addition to cash flow from ongoing operations would potentially include refinancing into a new reserve-based credit facility, selling all or a partial interest in our oil and natural gas assets, 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, 2019 and 2018 (in thousands):

	2019	2018	Change
Net cash provided by (used in):			
Operating activities	$ 638	$ (490)	$ 1,128
Investing activities	(281)	(1,310)	1,030
Financing activities	(1,165)	863	(2,028)

Operating Activities. Cash provided by operating activities for the year ended December 31, 2019 was $0.6 million as compared to cash used in operating activities of $0.5 million for 2018, an increase of $1.1 million. This increase was primarily related to the increase in oil revenues as a result of production increases in our South Texas properties.

Investing Activities. Cash used in investing activities for the year ended December 31, 2019 was $0.3 million compared to cash used in investing activities of $1.3 million for 2018, a decrease of $1.0 million. The decrease in cash used in investing activities was primarily attributable to a reduction in capital expenditures for oil and gas properties and the proceeds received from the sale of four wells in South Texas.

Financing Activities. Cash used in financing activities for the year ended December 31, 2019 was $1.2 million as compared to cash provided by financing activities of $0.9 million for 2018, a decrease of $2.1 million. The decrease was due to the $0.9 million repayment of the credit facility and a $0.2 million repayment of a note payable to finance insurance premiums during 2019. In 2018 cash provided by financing activities was primarily due to $1.7 million of proceeds, net of offering costs, from the at-the-market issuances of common stock, which was partially offset by a $0.6 million principal payment on our credit facility.

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 two-year period ended December 31, 2019.

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, 2019 our Chief Executive Officer and Principal Financial Officer determined that our disclosure controls and procedures were not effective to ensure that information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms and is accumulated and communicated to our management, including our Chief Executive Officer and Principal Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In connection with the termination of our former Chief Executive Officer in February 2019 and the dispute related thereto, we have been involved in pending litigation to resolve such disputes. See *Item 1. Business.—Litigation and Liquidity.* As a result of such pending litigation and lack of clarity with respect to the governance of the Company and the Audit Committee investigation we conducted in 2019 after our Audit Committee engaged independent legal counsel, which subsequently engaged an independent accounting firm to conduct a forensic accounting investigation of our expense reporting system in relation to issues raised by our auditors regarding potential financial improprieties related to expense reports, including examining expense reports and third-party expenditures made by or through our former Chief Executive Officer or his staff, we were unable to timely file our annual report on Form 10-K for the year ended December 31, 2018 as well as our quarterly reports on Form 10-Q for the fiscal quarters ended March 31, 2019 and June 30, 2019. Subsequently, we completed the filing of our delinquent annual report on Form 10-K and quarterly reports on Form 10-Q and put in place the remediation measures as described below.

Management's 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 GAAP. 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 our assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, 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 management, including our Chief Executive Officer and our Principal Financial Officer, our management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2019. In making its assessment, our management used the criteria set forth in the "Internal Control – Integrated Framework" (2013 framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on the evaluation conducted under this framework, our management concluded that our internal control over financial reporting was not effective as of December 31, 2019 for the reasons described below.

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. In connection with our management's assessment of our internal control over financial reporting as of December 31, 2019:

- We had inadequate segregation of duties as a result of limited accounting staff and resources, which has impacted our ability to prevent or detect material errors in our consolidated financial statements and to properly implement new accounting standards.
- We had inadequate controls over physical and logical access to our information technology systems.

Previously, our management identified the below deficiencies that constituted individually, or in the aggregate, material weaknesses in our internal control over financial reporting as of December 31, 2018. Other than the material weaknesses described above, which continue to exist as of December 31, 2019 we believe we have addressed and remediated the material weaknesses described below.

As of December 31, 2018, we had identified the following material weaknesses:

- We had inadequate segregation of duties as a result of limited accounting staff and resources, which impacted our ability to prevent or detect material errors in our consolidated financial statements.
- Our accounting staff did not have sufficient technical abilities to prevent or detect material errors in our consolidated financial statements including the implementation of new accounting standards.
- We did not maintain effective controls over our payment approval process to ensure that proper supporting documentation was received and reviewed prior to payments to third parties.
- We did not have effective controls over our information technology to prevent unauthorized access and control of our email and file servers.
- We did not effectively monitor expense reimbursements to ensure that only business expenses are reimbursed to employees on their expense reports.
- We did not have a process in place to identify related parties.
- We did not have a policy in place that required Board approval prior to the Company expending material amounts of Company funds in connection with evaluating potential acquisitions or transactions with third parties and vendors.

This annual report on Form 10-K 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 SEC that permit us to provide only management's report in this annual report on Form 10-K.

Changes in Internal Control Over Financial Reporting.

With the exception of the remediation efforts described below, there have been no changes to our system of internal control over financial reporting during the year and fiscal quarter ended December 31, 2019 and during the subsequent time period through the filing of this annual report on Form 10-K that have materially affected, or are reasonably likely to materially affect, our system of controls over financial reporting.

Following the Audit Committee investigation described above, we designed a remediation plan to strengthen our internal control over financial reporting and have taken, and will continue to take, remediation steps to address the material weaknesses identified as of December 31, 2018 including the material weaknesses we identified as continuing to exist as of December 31, 2019. We will also continue to take meaningful steps to enhance our disclosure controls and procedures and our internal controls over financial reporting.

Management's Remediation Plan

In response to the material weaknesses identified in "*Management's Report on Internal Control Over Financial Reporting*" above, we developed a plan (the "Remediation Plan") with oversight from our Audit Committee to remediate the material weaknesses and implemented the Remediation Plan prior to December 31, 2019. Our Remediation Plan implemented certain changes to our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act), including, but not limited to, the following efforts:

- Performing a full review of our system of internal control and evaluating the effectiveness of this system on an ongoing basis.
- Adding a professional to our accounting staff who has experience in implementing and maintaining an effective system of internal control and contracting with an outsource company experienced in oil and gas accounting to process our revenues and joint interest billings.
- Establishing effective segregation of duty controls, including segregation of duties to ensure the approval of disbursement transactions is performed by someone other than the person initiating the transaction.
- Creating and enforcing a written expense reimbursement policy that applies to both employees and Board members that (i) defines allowable expenses, (ii) requires pre-approval of expenditures above $500 in situations where personal conflicts of interest may exist; (iii) prohibits the payment of vendors and reimbursement through expense reports; (iv) outlines the documentation requirements for reimbursements, including receipts for meals or events exceeding $50, listing all parties at such meal and the business purposes of each meal or event; (v) requires detailed folios and receipts for all hotel stays; (vi) requires passenger information for all flights and a description of the business purpose of such travel; (vii) defines the levels of approval, including the approval of the Chief Executive Officer's expenses by the chairman of the Audit Committee and other officers' expenses by the Chief Executive Officer; (viii) establishes that all expenses must be submitted within 60 days of incurring the expense or such expense will not be subject to reimbursement; (ix) defines that all employees travel by coach for flights lasting less than three hours and by business class for flights lasting longer than three hours; and (x) defines the type of rental car allowed while traveling.
- Establishing that all checks or wire transfers issued by the Company require the approval of both the Chief Financial Officer and the Controller.
- Establishing a vendor approval process whereby any third-party vendors require approval by both the Chief Executive Officer and the Controller prior to engagement of such third-party vendors.

- Requiring employees and Board members to certify in writing at least annually that all potential conflicts of interest have been disclosed.
- Implementing a policy that prohibits employees from using Company vendors, including attorneys, accountants and consultants, for personal purposes without obtaining prior Board approval.
- Implementing a policy that clearly defines the types of potential projects or transactions that require prior Board approval prior to evaluating such potential project or transaction and incurring material expenses in connection with such evaluation, including due diligence.

Our management believes the foregoing efforts effectively remediated the material weaknesses identified as of December 31, 2018 other than the material weaknesses that management identified as continuing to exist as of December 31, 2019. As we continue to evaluate and work to improve our internal control over financial reporting, our management may determine to take additional measures to address control deficiencies or determine to modify the Remediation Plan. If not remediated, these control deficiencies could result in material misstatements to our consolidated financial statements in the future.

Additionally, as part of a continuing effort to improve our business processes, management is currently evaluating its existing internal controls and may update certain controls to accommodate any modifications to its business processes or accounting procedures.

Item 9B – Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item is incorporated by reference from U.S. Energy's Definitive Proxy Statement to its 2020 Annual Meeting of Shareholders to be filed not later than April 29, 2020.

Item 11. Executive Compensation.

The information required by this Item is incorporated by reference from U.S. Energy's Definitive Proxy Statement to its 2020 Annual Meeting of Shareholders to be filed not later than April 29, 2020.

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

The information required by this Item is incorporated by reference from U.S. Energy's Definitive Proxy Statement to its 2020 Annual Meeting of Shareholders to be filed not later than April 29, 2020.

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

The information required by this Item is incorporated by reference from U.S. Energy's Definitive Proxy Statement to its 2020 Annual Meeting of Shareholders to be filed not later than April 29, 2020.

Item 14. Principal Accounting Fees and Services.

The information required by this Item is incorporated by reference from U.S. Energy's Definitive Proxy Statement to its 2020 Annual Meeting of Shareholders to be filed not later than April 29, 2020.

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 sheets of U.S. Energy Corp. and subsidiary (the "Company") as of December 31, 2019 and 2018 and the related consolidated statements of operations, changes in shareholders' equity and cash flows for each of the years in the two-year period ended December 31, 2019, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2019 and 2018, and the consolidated results of its operations and its cash flows for the years ended December 31, 2019 and 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

The Company's management is responsible for these consolidated financial statements. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the 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 audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. 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 audits, 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 audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures 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 audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Plante & Moran PLLC

We have served as the Company's auditor since 2018.
Denver, Colorado
March 30, 2020

U.S. ENERGY CORP. AND SUBSIDIARY
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2019 AND 2018
(in thousands, except share and per share amounts)

	2019	2018
ASSETS		
Current assets:		
Cash and equivalents	$ 1,532	$ 2,340
Oil and natural gas sales receivable	716	697
Related party receivable	-	2
Marketable equity securities	307	536
Prepaid and other current assets	138	113
Total current assets	2,693	3,688
Oil and natural gas properties under full cost method:		
Unevaluated properties	3,741	3,728
Evaluated properties	89,113	88,764
Less accumulated depreciation, depletion and amortization	(84,400)	(83,729)
Net oil and natural gas properties	8,454	8,763
Other assets:		
Property and equipment, net	2,115	2,249
Right of use asset	179	-
Other assets	26	78
Total other assets	2,320	2,327
Total assets	$ 13,467	$ 14,778
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 974	$ 670
Current lease obligation	58	-
Accrued compensation and benefits	191	63
Current portion of credit facility	-	937
Total current liabilities	1,223	1,670
Noncurrent liabilities:		
Asset retirement obligations	819	939
Warrant liability	73	425
Long-term lease obligation, net of current portion	142	-
Other noncurrent liabilities	-	25
Total noncurrent liabilities	1,034	1,389
Total liabilities	2,257	3,059
Commitments and contingencies (Note 11)		
Preferred stock: Authorized 100,000 shares, 50,000 shares of Series A Convertible (par value $0.01) issued and outstanding; liquidation preference of $3,228 and $2,856 as of December 31, 2019 and 2018, respectively	2,000	2,000
Shareholders' equity:		
Common stock, $0.01 par value; unlimited shares authorized; 1,340,583 shares issued and outstanding	13	13
Additional paid-in capital	136,876	136,835
Accumulated deficit	(127,679)	(127,129)
Total shareholders' equity	9,210	9,719

Total liabilities, preferred stock and shareholders' equity	$ 13,467	$ 14,778

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

U.S. ENERGY CORP. AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2019 and 2018
(in thousands, except share and per share amounts)

	2019	2018
Revenue:		
Oil	$ 6,149	$ 4,609
Natural gas and liquids	424	930
Total revenue	6,573	5,539
Operating expenses:		
Oil and natural gas operations:		
Lease operating expense	1,848	1,898
Production taxes	429	392
Depreciation, depletion, accretion and amortization	693	393
General and administrative:		
Compensation and benefits	1,187	2,089
Professional fees, insurance and other	3,178	1,540
Bad debt expense	28	374
Total operating expenses	7,363	6,686
Operating Loss	(790)	(1,147)
Other income (expense):		
Realized loss on commodity price risk derivatives	-	(283)
Unrealized gain on commodity price risk derivatives	-	161
Recovery of deposit	200	-
Loss on marketable equity securities	(229)	(339)
Rental and other loss	(72)	(114)
Warrant revaluation gain	352	775
Interest expense, net	(11)	(93)
Total other income	240	107
Net loss	**$ (550)**	**$ (1,040)**
Accrued preferred stock dividends	$ (372)	$ (329)
Net loss applicable to common shareholders	**$ (922)**	**$ (1,369)**
Basic and diluted weighted average shares outstanding	1,340,583	1,288,857
Basic and diluted net loss per share	$ (0.69)	$ (1.06)

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

U.S. ENERGY CORP. AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2019 and 2018
(in thousands, except share amounts)

	Common Stock		Additional Paid-in	Accumulated	
	Shares	Amount	Capital	Deficit	Total
Balances, December 31, 2017 (restated)	1,180,276	$ 12	$ 134,738	$ (126,089)	$ 8,661
Issuance of shares in at-the-market transactions, net of fees	128,853	1	1,665	-	1,666
Issuance of shares to employees, net of shares withheld for taxes	31,454	-	379	-	379
Amortization of stock option awards	-	-	53	-	53
Net loss	-	-	-	(1,040)	(1,040)
Balances, December 31, 2018	1,340,583	$ 13	$ 136,835	$ (127,129)	$ 9,719
Amortization of stock option awards	-	-	41	-	41
Net loss	-	-	-	(550)	(550)
Balances, December 31, 2019	1,340,583	$ 13	$ 136,876	$ (127,679)	$ 9,210

As the result of adoption of ASU 2016-01, the December 31, 2017, accumulated deficit has been adjusted by $903 thousand representing the accumulated other comprehensive loss related to marketable equity securities on that date.

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

U.S. ENERGY CORP. AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018
(in thousands)

	2019	2018
Cash flows from operating activities:		
Net loss	$ (550)	$ (1,040)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion, accretion, and amortization	828	526
Debt issuance cost amortization	7	12
Change in fair value of commodity derivative	-	(161)
Change in fair value of warrants	(352)	(775)
Bad debt write-off	28	374
Stock-based compensation and services	41	636
Loss on marketable equity securities	229	339
Right of use asset amortization	48	-
Other	-	3
Changes in operating assets and liabilities:		
Decrease (increase) in:		
Oil and natural gas sales receivable	(49)	(10)
Other current assets	231	(108)
Increase (decrease) in:		
Accounts payable accrued liabilities	100	(283)
Accrued compensation and benefits	129	(3)
Payments on operating lease liability	(52)	-
Net cash provided by (used in) operating activities	638	(490)
Cash flows from investing activities:		
Oil and natural gas capital expenditures	(376)	(1,301)
Settlement of asset retirement obligations	-	(18)
Proceeds from sale of oil and natural gas properties	75	-
Purchase of property and equipment	-	(11)
Payment received on notes receivable	20	20
Net cash used in investing activities:	(281)	(1,310)
Cash flows from financing activities:		
Issuance of common stock, net of fees	-	1,666
Shares repurchased for employee tax withholding	-	(203)
Payments on insurance premium finance note	(228)	-
Payments on credit facility	(937)	(600)
Net cash (used in) provided by financing activities	(1,165)	863
Net decrease in cash and equivalents	(808)	(937)
Cash and equivalents, beginning of year	2,340	3,277
Cash and equivalents, end of year	$ 1,532	$ 2,340

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

U.S. ENERGY CORP. AND SUBSIDIARY
CONSOLIDATED STATEMENTS OF CASH FLOWS, Continued
FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018
(in thousands)

	2019	2018
Supplemental disclosures of cash flow information and non-cash activities:		
Cash payments for interest	$ 11	$ 119
Investing activities:		
Change in capital expenditure accruals	176	196
Exchange of undeveloped acreage for oil and gas properties	379	-
Asset retirement obligations assumed by purchaser	130	-
Adoption of lease standard	252	-
Asset retirement obligations	14	19
Reclassification of assets classified as held-for-sale at December 31, 2017 to other assets	-	653
Financing activities:		
Financing of insurance premiums with note payable	228	-

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

U.S. ENERGY CORP. AND SUBSIDIARY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Organization and Operations

U.S. Energy Corp. (collectively with its wholly owned subsidiary, Energy One LLC, referred to as the "Company" in these Notes to Consolidated Financial Statements) 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 natural 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 ("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 natural gas reserves that are used in the calculation of depreciation, depletion, amortization and impairment of the carrying value of evaluated oil and natural gas properties; realizability of unevaluated properties; production and commodity price estimates used to record accrued oil and natural gas sales receivables; valuation of warrant instruments; 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 natural 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 U.S. Energy Corp. 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 in the consolidated statement of operations have been reclassified to conform to the current period presentation as follows:

- Stock-based compensation of $636 thousand for the year ended December 31, 2018 has been included in Compensation and benefits.
- Interest income of $13 thousand for the year ended December 31, 2018, which was included as a component of Rental and other loss has been reclassified to Interest expense, net.

Reverse Stock Split

On January 6, 2020, the Company completed a one share-for-ten shares reverse stock split with respect to the Company's common stock. For purposes of presentation, the consolidated financial statements and footnotes have been adjusted for the number of post-split shares as if the split had occurred at the earliest period presented.

Liquidity and Resources

In the Company's Annual Report on Form 10-K for the year ended December 31, 2018 it reported that there was substantial doubt regarding its ability to fund operations for the next twelve months and continue as a going concern. The substantial doubt was primarily related to uncertainty regarding continuing expenditures in the APEG II litigation. Although the litigation remains pending, the Company believes that the expenditures related to the litigation are substantially complete. During 2019, the Company took many steps to preserve liquidity including reducing the use of third-party contractors, cutting corporate overhead and eliminating other general and administrative costs. Additionally, in March 2020, there has been a significant decline in commodity prices. While the Company expects to experience a decrease in its oil and natural gas revenue, it believes that its existing cash and capital resources and its forecasted low overhead costs going forward have alleviated the substantial doubt regarding its ability to continue as a going concern and the Company expects that it will be able to fund operations for the next twelve months.

Cash and Equivalents

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

Oil and Natural Gas Sales Receivable

The Company's oil and natural gas sales receivable consist primarily of receivables from joint interest operators for the Company's share of oil, natural gas, and natural gas liquids ("NGLs") sales. Generally, the Company's oil and natural gas sales receivables are collected within three months. The Company has had minimal bad debts related to oil and natural gas sales. Although diversified among several joint interest operators, collectability is dependent upon the financial wherewithal of each joint interest operator and is influenced by the general economic conditions of the industry. Receivables are not collateralized. As of December 31, 2019 and 2018, the Company had not provided an allowance for doubtful accounts on its oil and natural gas sales receivable.

Concentration of Credit Risk

The Company has exposure to credit risk in the event of nonpayment of oil and natural gas receivables by joint interest operators of the Company's oil and natural gas properties. The following table presents the joint interest operators that accounted for 10% or more of the Company's total oil and natural gas revenue for at least one of the periods presented:

Operator	2019	2018
CML Exploration, LLC	52%	18%
Zavanna, LLC	31%	47%
Crimson Exploration Operating, Inc.	7%	14%

Marketable Equity Securities

Marketable equity securities are reported at fair value based on end of period quoted prices. Beginning in 2018, the Company adopted Accounting Series Update 2016-01, which requires an entity to measure equity investments at fair value through net income. Previously, the Company had classified marketable equity securities as available for sale and recorded changes in value as a component of shareholders' equity within comprehensive income or loss. Gains or losses from sales of marketable equity securities are recorded in the consolidated statement of operations when realized.

Oil and Natural Gas Properties

The Company follows the full cost method of accounting for its oil and natural gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and natural 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 natural 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.

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 Mcf 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 qualifying as accounting hedges 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 natural gas properties. If the net book value reduced by the related net deferred income tax liability (if any) 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 natural 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

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 has used derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk underlying its oil and natural 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 such derivative instruments provide an economic hedge of the Company's exposure to commodity price risk associated with forecasted future oil and natural gas production, the Company does not designate any of its derivative instruments as cash flow hedges. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its accompanying statements of operations as they occur. Gains and losses on derivatives are included within cash flows from operations in the accompanying consolidated statements of cash flows.

Warrant Liability

In connection with a private placement of common shares in December 2016, the Company concurrently sold to the purchasers warrants to purchase 100,000 shares of common stock. The exercise price and the number of shares issuable upon exercise of the warrants is subject to adjustment in the event of any stock dividends and splits, reverse stock splits, recapitalization, reorganization or similar transaction, as described in the warrants. The warrants are also subject to "down-round" anti-dilution in the event the Company issues additional common stock or common stock equivalents at a price per share less than the exercise price in effect. The Company has classified the warrants as liabilities due to provisions in the warrant agreement that precluded equity classification, including an option of the holder to receive the calculated fair value of the warrant from the Company in cash in the event of a "Fundamental Transaction," as defined in the warrant agreement. Changes in fair value are reported each period in the consolidated statements of operations.

Asset Retirement Obligations

The Company records the estimated fair value of restoration and reclamation liabilities related to its oil and natural gas 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.

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 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 option pricing model. The Company recognizes the cost of the equity awards over the period during which an employee is required to provide services in exchange for the award, usually the vesting period. For awards granted that 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, whereas 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 that, based on current circumstances, are not expected to be realized. At December 31, 2019 and 2018, management believed it was more likely than not that such tax benefits would not be realized and a valuation allowance has been provided. In assessing the need for a valuation allowance for the Company's deferred tax assets, a significant item of negative evidence considered was the cumulative book loss over the three-year period ended December 31, 2019.

The Company assesses its uncertain tax positions annually. The Company recognizes the tax benefit from an uncertain tax position only if it is probable that the tax position will be sustained on examination by taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that is probable of being realized upon ultimate settlement. The amount of unrecognized tax benefits is adjusted as appropriate for changes in facts and circumstances, such as significant amendments to existing tax law, new regulations or interpretations by the taxing authorities, new information obtained during a tax examination, or resolution of an examination.

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, warrants and the Series A preferred stock. 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

Leases. In February 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-02, *Leases (Topic 842)*, followed by other related ASUs that targeted improvements and additional practical expedient options (collectively "ASU 2016-02"). The standard requires lessees to recognize right-of-use assets and lease payment liabilities on the balance sheet for leases representing the Company's right to use the underlying assets for the lease term. Each lease that is recognized in the balance sheet is classified as either finance or operating, with such classification affecting the pattern and classification of expense recognition in the condensed consolidated statements of operations and presentation within the condensed consolidated statements of cash flow.

The Company evaluated the impacts of ASU 2016-02, which included an analysis of contracts for office leases. As a non-operator of oil and natural gas properties, the Company is not subject to drilling rig agreements, well completion agreements, water handling agreements, or other contracts that include potential lease components. In addition, the scope of ASU 2016-02 does not apply to leases used in the exploration or use of minerals, oil, natural gas or other similar non-regenerative resources. See *Note 3-Leases* for additional information regarding the Company's adoption of this standard including policy elections and the impact to the consolidated financial statements at December 31, 2019.

Financial instruments with characteristics of liabilities and equity. On July 13, 2017, the FASB issued a two-part ASU No. 2017-11, I. Accounting for Certain Financials Instruments with Down Round Features and II. Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interest with a Scope Exception. The ASU was effective for public business entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018. The Company assessed the new standard as it relates to warrants issued by the Company in December 2016, which contain a down round feature. The Company determined through an assessment of the warrants in relation to *ASC 815-40, Derivatives and Hedging-Contracts in Entity's Own Equity*, that there were other provisions in the warrant agreement that precluded equity classification, including an option of the holder to receive the calculated fair value of the warrant from the Company in cash in the event of a "Fundamental Transaction," as defined in the warrant agreement. Therefore, the Company will continue to classify the warrants as liabilities with fair value changes recorded in the period of change in other income in the consolidated statement of operations.

Fair Value Measurements. In August 2018, the FASB issued ASU No. 2018-13, *Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurements*. The ASU amends the disclosure requirements in Topic 820, *Fair Value Measurements*. The amendments in this ASU are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The Company plans to adopt this ASU as of January 1, 2020. The Company is in the process of assessing the impact the adoption of this ASU will have on its fair value disclosures.

2. REVENUE RECOGNITION

The Company's revenues are derived from its interest in the sales of oil and natural gas production. The sales of oil and natural gas are made under contracts that operators of the wells have negotiated with third-party customers. The Company receives payment from the sale of oil and natural gas production between one to three months after delivery. At the end of each period when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in oil and natural gas sales receivable in the consolidated balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received; however, differences have been and are insignificant. Accordingly, the variable consideration is not constrained. As a non-operator of its oil and natural gas properties, the Company records its share of the revenues and expenses based upon the information provided by the operators within the revenue statements.

The Company does not disclose the values of unsatisfied performance obligations under its contracts with customers as it applies the practical exemption in accordance with ASC 606. The exemption applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to the remaining performance obligations is not required.

The Company's oil and natural gas production is typically sold at delivery points to various purchasers under contract terms that are common in the oil and natural gas industry. Regardless of the contract type, the terms of these contracts compensate the well operators for the value of the oil and natural gas at specified prices, and then the well operators remit payment to the Company for its share in the value of the oil and natural gas sold.

Generally, the Company reports revenue as the gross amount received from the well operators before taking into account production taxes and transportation costs. Production taxes are reported separately and transportation costs are included in lease operating expense in the accompanying consolidated statements of operations. The revenue and costs in the consolidated financial statements were reported gross for the years ended December 31, 2019 and 2018, as the gross amounts were known.

The Company's disaggregated revenues from its share of revenue from the sale of oil and natural gas and liquids in its North Dakota, Texas and Louisiana regions are presented in the following table:

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Revenue:		
North Dakota		
Oil	$ 2,449	$ 2,925
Natural gas and liquids	177	320
Total	2,626	3,245
Texas		
Oil	3,700	1,684
Natural gas and liquids	247	278
Total	3,947	1,962
Louisiana		
Oil	-	-
Natural gas and liquids	-	332
Total	-	332
Combined Total	$ 6,573	$ 5,539

3. LEASES

On January 1, 2019, the Company adopted ASC 842 using the modified retrospective approach. Results for the reporting periods beginning January 1, 2019 are presented in accordance with ASC 842, while prior period amounts are reported in accordance with FASB ASC Topic 840-Leases. On January 1, 2019, the Company recorded a $228 thousand right-of-use asset and a $252 thousand lease liability representing the present value of minimum payment obligations associated with its Denver office operating lease, which has non-cancellable terms in excess of one year. We do not have any financing leases. The Company has elected the following practical expedients available under ASC 842 (i) excluding from the consolidated balance sheet leases with terms that are less than one year, (ii) for agreements that contain both lease and non-lease components, combining these components together and accounting for them as a single lease, (iii) the package of practical expedients, which allows the Company to avoid reassessing contracts that commenced prior to adoption that were properly evaluated under legacy GAAP, and (iv) the policy election that eliminates the need for adjusting prior period comparable financial statements prepared under legacy lease accounting guidance. As such, there was no required cumulative effect adjustment to accumulated deficit at January 1, 2019.

During the year ended December 31, 2019, the Company did not acquire any right-of-use assets or incur any lease liabilities. The Company's right-of-use assets and lease liabilities are recognized at their discounted present value on the consolidated balance sheet at December 31, 2019, of $179 thousand and $200 thousand, respectively.

	December 31, 2019
	(in thousands)
Right-of-use asset balance	
Operating lease	$ 179
Lease liability balance	
Short-term operating lease	$ 58
Long-term operating lease	142
Total liability operating leases	$ 200

The Company recognizes lease expense on a straight-line basis excluding short-term and variable lease payments which are recognized as incurred. Short-term lease costs represent payments for our Houston office lease, which has a lease term of one year.

	December 31, 2019
	(in thousands)
Operating lease cost	$ 68
Short-term lease cost	15
Total lease cost	$ 83

The Company’s Denver office operating lease does not contain an implicit interest rate that can be readily determined. Therefore, the Company used the incremental borrowing rate of 8.75% as established under the Company’s prior credit facility as the discount rate.

	December 31, 2019
Weighted average lease term (years)	3.1
Weighted average discount rate	8.75%

The future minimum lease commitments as of December 31, 2019 are presented in the table below. Such commitments are reflected at undiscounted values and are reconciled to the discounted present value on the consolidated balance sheet as follows:

	December 31, 2019
	(in thousands)
2020	73
2021	75
2022	76
2023	6
Total lease payments	$ 230
Less: imputed interest	(30)
Total lease liability	$ 200

The Company owns a 14-acre tract in Riverton, Wyoming with a two-story, 30,400 square foot office building, which served as the Company's corporate headquarters until the Company relocated its corporate headquarters in 2015. Currently, the building's eight office suites are rented to non-affiliates and government agencies under operating leases with varying terms from month-to-month to twelve years. The building is included in property and equipment, net on our consolidated balance sheet. The net capitalized cost of the building subject to operating leases at December 31, 2019 is as follows:

	December 31, 2019
	(in thousands)
Building subject to operating leases	$ 4,012
Less: accumulated depreciation	(3,244)
Building subject to operating leases, net	$ 768

The future lease maturities of the Company's operating leases as of December 31, 2019 are presented in the table below. Such maturities are reflected at undiscounted values to be received on an annual basis.

	December 31, 2019
	(in thousands)
2020	158
2021	161
2022	165
2023	169
2024	163
Remaining through June 2029	695
Total lease maturities	$ 1,511

The Company recognized, as a component of Rental and other loss, the following operating lease income related to its Riverton, Wyoming office building for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Operating lease income	$ 207	$ 186

4. COMMODITY PRICE RISK DERIVATIVES

Energy One from time to time enters into commodity price derivative contracts ("economic hedges"). The derivative contracts are typically priced based on West Texas Intermediate ("WTI") quoted prices for crude oil and Henry Hub quoted prices for natural gas. U.S. Energy Corp. guarantees Energy One's obligations under 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 natural 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. At December 31, 2019 and 2018 the Company did not have any outstanding commodity price derivative contracts. The following table presents the Company's realized and unrealized derivative gains and losses for the years ended December 31, 2019 and 2018:

	Year Ended December 31,	
	2019	**2018**
	(in thousands)	
Net derivative gain (loss):		
Realized gains and (losses):		
Oil	$ -	$ (292)
Natural gas	-	9
Total	-	(283)
Unrealized gains and (losses):		
Oil	-	216
Natural Gas	-	(55)
Total	$ -	$ 161

5. OIL AND NATURAL GAS PRODUCING ACTIVITIES

Divestitures

In December 2019, the Company completed the sale of its interest in four Texas wells for $75 thousand in cash and assumption of $130 thousand of asset retirement obligations associated with the wells. The total was recorded as a reduction in the balance of the full cost pool.

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, 2019, the Company used $55.69 per barrel for oil and $2.58 per mcf 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%.

There was no impairment for the years ended December 31, 2019 and 2018 of the Company's oil and natural gas properties. Impairment charges in previous years are generally the result of declines in the price of oil and natural gas, additional capitalized well costs and changes in production.

6. PROPERTY AND EQUIPMENT, NET

Property and equipment consist of the following as of December 31, 2019 and 2018:

	2019	2018
	(in thousands)	
Real estate:		
Land	$ 1,033	$ 1,033
Buildings	4,012	4,012
Land improvements	641	641
Administrative assets:		
Computers and software	379	378
Office furniture and equipment	224	224
Vehicles and other	11	11
Total	6,300	6,299
Less accumulated depreciation	(4,185)	(4,050)
Property and equipment, net	$ 2,115	$ 2,249

Depreciation expense related to the Company's real estate assets in Riverton, Wyoming amounted to $122 thousand and $121 thousand for the years ended December 31, 2019 and 2018, respectively and is included as a component of rental loss and other in the consolidated statement of operations. Depreciation expense related to the Company's administrative assets amounted to $13 thousand and $12 thousand for the years ended December 31, 2019 and 2018, respectively and is included as a component of general and administrative expenses in the consolidated statement of operations.

7. DISPOSITION OF MINING SEGMENT

In February 2016, the Company disposed of its mining segment consisting of the Mt. Emmons molybdenum mining properties (the "Property"). Related to the disposition, 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 water treatment plant ("WTP") and other related properties. Under the Acquisition Agreement, MEM replaced the Company as the permittee and operator of the WTP and has discharged the obligation of the Company to operate the WTP 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 MEM desires to retain. 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 pursuant to which the Company issued 50,000 shares of Series A Convertible Preferred Stock to MSM (see *Note 12-Preferred Stock*).

8. WRITE-OFF OF DEPOSIT

In December 2017, the Company entered into a Letter of Intent ("LOI") with Clean Energy Technology Association, Inc. ("CETA") to purchase an option to acquire 50 shares of CETA, or lease certain oil and natural gas properties inside an area of mutual interest. The Company made a $250,000 option payment, which was refundable in the event that the Company and CETA were unable to complete the transaction by August 1, 2018. In 2018, the Company paid an additional $124,000 to CETA. In September 2019, the Company issued CETA a demand letter requesting return of the amounts deposited. As of March 20, 2020, the Company has received four payments from CETA totaling $200,000. While the Company is pursuing collection of the remaining deposit, the Company has established an allowance of $174,000 due from CETA at December 31, 2019, due to the uncertainty of collection of the deposit. See *Note 11-Commitments, Contingencies and Related Party Transactions.*

9. DEBT

On December 27, 2017, the Company entered into an exchange agreement ("Exchange Agreement") by and among U.S. Energy Corp., Energy One and APEG II, pursuant to which, on the terms and subject to the conditions of the Exchange Agreement, APEG II exchanged $4.5 million of outstanding borrowings under the Company's credit facility, for 581,927 newly-issued shares of common stock of the Company, par value $0.01 per share, with an exchange price of $7.67, which represented 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 II was paid in cash at the closing of the transaction. At December 31, 2019, APEG II held approximately 43% of the Company's outstanding common stock.

The credit facility was fully repaid at March 1, 2019 and on July 30, 2019, matured and was terminated. At December 31, 2018, outstanding borrowings under the credit facility were $937 thousand. Borrowings under the credit facility were secured by Energy One's oil and natural gas producing properties. Interest expense for the year ended December 31, 2019 was $20 thousand, including the amortization of debt issuance costs of $7 thousand. Interest expense for the year ended December 31, 2018 was $106 thousand including amortization of debt issuance costs of $12 thousand. The weighted average interest rate on the credit facility was 8.75% for the period until maturity in 2019 and the year ended December 31, 2018. APEG II is involved in litigation with the Company and its former Chief Executive Officer, as described in *Note 11-Commitments, Contingencies and Related Party Transactions*.

10. ASSET RETIREMENT OBLIGATIONS

The Company has asset retirement obligations ("ARO") associated with the future plugging and abandonment of developed oil and gas properties. Initially, the fair value of a liability for an ARO is recorded in the period in which the ARO is incurred with a corresponding increase in the carrying amount of the related asset. The liability is accreted to its present value each period and the capitalized cost is depleted over the life of the related asset. If the liability is settled for an amount other than the recorded amount, an adjustment to the full-cost pool is recognized. The Company had no assets that are restricted for the purpose of settling AROs.

In the fair value calculation for the ARO there are numerous assumptions and judgments including the ultimate retirement cost, inflation factors, credit-adjusted risk-free discount rates, timing of retirement and changes in legal, regulatory, environmental and political environments. To the extent future revisions to assumptions and judgments impact the present value of the existing ARO, a corresponding adjustment is made to the oil and natural gas property balance. During the year ended December 31, 2019 we adjusted the credit-adjusted risk-free discount rate used in calculating present value of the ARO for a well that began production in 2018.

The following is a reconciliation of the changes in the Company's liabilities for asset retirement obligations for the years ended December 31, 2019 and 2018:

	2019	2018
	(in thousands)	
Balance, beginning of year	$ 939	$ 913
Accretion	22	25
Sold/Plugged	(130)	(18)
New drilled wells	2	19
Change in discount rate	(14)	-
Liabilities incurred	-	-
Balance, end of year	$ 819	$ 939

11. COMMITMENTS, CONTINGENCIES, AND RELATED PARTY TRANSACTIONS

Litigation

APEG Energy II, L.P. ("APEG II") and its general partner, APEG Energy II, GP (together with APEG II, "APEG") are involved in litigation with the Company and its former Chief Executive Officer, David Veltri, as described below. As of December 31, 2019, APEG II held approximately 43% of the Company's outstanding common stock and was the secured lender prior to the maturity of the credit facility on July 30, 2019. The costs associated with the pending litigation were a significant use of existing cash during 2019, but the Company believes the expenditures are substantially complete.

APEG II Litigation

On February 14, 2019, the Company's Board of Directors (only one member of which remains on the Board following the Company's 2019 Annual Meeting of Shareholders held on December 10, 2019) received a letter from APEG II urging the Company to establish a seven-person, independent board of directors, establish a corporate business plan and reduce its corporate general and administrative expenses. APEG II is the Company's largest shareholder, owning approximately 41% of its outstanding common stock, and, as of December 31, 2018, was the secured lender under its credit facility, which the Company repaid in full as discussed below.

On February 25, 2019, APEG II provided an access termination notice to the Company's bank under its collateral documents, which resulted in all of the funds held in the collateral accounts, which totaled approximately $1.8 million, being wired to APEG II on March 1, 2019. On March 1, 2019, David Veltri, the Company's former Chief Executive Officer and President, filed a lawsuit against APEG II in the Company's name (the "Texas Litigation"). The Texas State Court granted the motion for a temporary restraining order ("TRO") and ordered APEG to return immediately the approximate $1.8 million in cash previously wired to APEG II.

On March 4, 2019, APEG II filed an emergency motion with the U.S. District Court for the Southern District of Texas in order to remove the Texas Litigation from the State Court to the Federal District Court and to stay or modify the TRO. Following a hearing on March 4, 2019, the Texas Federal Court vacated the TRO and the Court ordered APEG to return the Company's funds, less the outstanding balance due to APEG II under the credit facility of approximately $937 thousand, and the Company received approximately $850 thousand.

On February 25, 2019, the Company's Board held a meeting at which it voted to terminate Mr. Veltri for cause as Chief Executive Officer and President as a result of using Company funds outside of his authority and other reasons. Mr. Veltri, along with John Hoffman, a former Board member, called into question whether or not such action was properly taken at the Board meeting. On March 8, 2019, the Company's Audit Committee intervened in the Texas Litigation by filing an emergency motion (the "AC

Motion”). The AC Motion requested that the Texas Federal Court order that all of the Company’s funds and matters be placed under the control of our Chief Financial Officer and that control of these functions be removed from our former Chief Executive Officer, who had been terminated by our Board on February 25, 2019.

On March 12, 2019, the Texas Federal Court granted the AC Motion, ordering that any disbursement made by the Company must be approved in writing by the Audit Committee in advance. Additionally, the Texas Federal Court ordered that the Company’s Chief Financial Officer must be appointed as the sole signatory on all of the Company’s bank accounts.

Litigation with Former Chief Executive Officer

In connection with the above described litigation with APEG II, APEG II then initiated a second lawsuit on March 18, 2019 as a shareholder derivative action in Colorado against Mr. Veltri, as a result of his refusal to recognize the Board's decision to terminate him for cause (the "Colorado Litigation"). The Company was named as a nominal defendant in the Colorado Litigation. The APEG II complaint in the Colorado Litigation alleged that Mr. Veltri's employment was terminated by the Board of Directors and sought an injunction and temporary restraining order against Mr. Veltri to prevent him from continuing to act as the Company's Chief Executive Officer, President and Chairman.

On April 30, 2019, the Audit Committee took over the control of the defense of the Company, prosecution of its claims against APEG II, and filed third-party claims on behalf of the Company against Mr. Veltri and Mr. Hoffman, at the time a director of the Company, asserting that Mr. Veltri was responsible for any damages that APEG II claims, including attorneys' fees, and that Mr. Veltri and Mr. Hoffman should be removed from the Board of Directors. On May 22, 2019, the Company and APEG II entered into a settlement agreement with Mr. Hoffman, pursuant to which Mr. Hoffman agreed to resign from the Board of Directors and committees thereof, and we agreed to pay up to $50,000 of his legal fees incurred. Further, the Company released Mr. Hoffman from any claims related to the Texas Litigation, APEG II released the Company from any claims that may have been caused by Mr. Hoffman, and Mr. Hoffman released us from any and all claims he may have had against the Company and its Board.

In the Colorado Litigation, the Colorado Federal Court granted interim preliminary injunctive relief to APEG II against Mr. Veltri, holding that Mr. Veltri, without authorization, continued to hold himself out to be, and continued to act as, as the Company's President and Chief Executive Officer. Pursuant to the Order, Mr. Veltri was preliminarily enjoined from acting as, or holding himself out to be, the Company's President and/or Chief Executive Officer, pending a trial on the merits. Ryan Smith, the Company's Chief Financial Officer, was appointed temporary custodian of the Company with the charge to act as the Company's Interim Chief Executive Officer.

On May 30, 2019, the Colorado Federal Court issued a subsequent order (the "Second Order"), appointing C. Randel Lewis as custodian of the Company pursuant to the Wyoming Business Corporation Act and to take over for Mr. Smith in acting as The Company's Interim Chief Executive Officer and to serve on the Board of Directors as Chairman. The Second Order noted that the primary purpose of having Mr. Lewis serve as custodian was to resolve the Board deadlock regarding Mr. Veltri's termination. Pursuant to the Second Order, Mr. Lewis, as custodian, was ordered to act in place of the Board to appoint one independent director to replace Mr. Hoffman. On June 13, 2019, Mr. Lewis appointed Catherine J. Boggs to serve as an independent director until the 2019 annual meeting of the Company's shareholders, which was held on December 10, 2019. Following such annual meeting, the Board appointed Ryan Smith to serve as the Company's Chief Executive Officer to replace Mr. Lewis in that role. Following the annual meeting, the Colorado Federal Court also discharged Mr. Lewis from serving as custodian, Interim Chief Executive Officer and as a member of the Board.

Both the Texas Litigation and the Colorado Litigation currently remain pending.

Audit Committee Investigation

Following the termination of Mr. Veltri on February 25, 2019, the Company's independent auditors, Plante & Moran PLLC, informed the Audit Committee that the auditors had found irregularities in the submission and payment of expense reports with respect to the Company's former Chief Executive Officer. The Audit Committee engaged independent legal counsel, which subsequently engaged an independent accounting firm to conduct a forensic accounting investigation of the Company's expense reporting system in relation to issues raised by the Company's auditors regarding potential financial improprieties related to expense reports, including examining expense reports and third-party expenditures made by or through the Company's former Chief Executive Officer or his staff. The investigation was expanded into a forensic investigation of the integrity of the Company's computer-based record-keeping after Mr. Veltri and Mr. Hoffman managed to reset the security codes to give them complete control of the Company's books and records temporarily and exclude the Company's other employees', members of management's, other officer's and director's ability to access those records during that period, which further raised concerns with respect to material weaknesses in the Company's internal control over financial reporting. The scope of the forensic accounting investigation covered the period from January 1, 2017 through March 31, 2019. Our Audit Committee took certain steps in response to the forensic accounting investigation. See "*Item 9A. Controls and Procedures—Changes in Control Over Financial Reporting—Management's Remediation Plan*."

The forensic accounting investigation and our internal investigation also identified numerous expense items on Mr. Veltri's expense reports that appeared to be personal in nature, or lacked adequate documentation showing that such expense was for legitimate business purposes. These expense items totaled at least $81,014, of which $32,194 was incurred during the year ended December 31, 2017, $34,203 was incurred during the year ended December 31, 2018 and $14,617 was incurred during 2019 prior to Mr. Veltri's termination. The Company reclassified the entire $81,014 reimbursed to Mr. Veltri as additional compensation and taxable income.

The report also indicated that Mr. Veltri used the Company's vendors for his own personal benefit. Mr. Veltri bypassed the Company's accounts payable process by paying third-party vendors personally through expense reports and then approved his own expense reports, which limited the visibility of the payments and review by the Company's accounting personnel.

Mr. Veltri also incurred $47,156 in third-party professional fees in connection with a potential transaction with a company controlled by a former Board member, which transaction and related expenses in evaluating the potential transaction were not approved by the Board. At December 31, 2018, the total amount of the fees was impaired and transferred to the full cost pool.

Mr. Veltri also entered into an agreement to acquire some oil and natural gas properties for which the Board authorized $250,000, which amount was fully refundable, subject to the funds being held in escrow pending the closing of the acquisition. Mr. Veltri wired the funds directly into the seller's account, rather than escrowing such funds, and also paid the seller an additional $124,328, which amount was not authorized by the Board, as well as $40,578 for professional services. The transaction never closed. As of December 31, 2019, the Company has received refunds totaling $150,000 of such funds from the seller and in January 2020 the Company received an additional $50,000, which was accrued at December 31, 2019.

12. 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.

On February 12, 2016, the Company issued 50,000 shares of newly designated Series A Convertible Preferred Stock (the "Preferred Stock") to Mt. Emmons Mining Company ("MEM"), a subsidiary of Freeport McMoRan, pursuant to that certain Series A Convertible Preferred Stock Purchase Agreement (the "Series A Purchase Agreement"). The Preferred Stock was issued in connection with the disposition of the Company's mining segment, whereby MEM acquired the property and replaced the Company as permittee and operator of a water treatment plant (the "Acquisition Agreement"). The Preferred Stock was issued at $40 per share for an aggregate $2 million. The Preferred Stock liquidation preference, initially $2 million, increases by quarterly dividends of 12.25% per annum (the "Adjusted Liquidation Preference"). At the option of the holder, each share of Preferred Stock may initially be converted into 1.33 shares of the Company's $0.01 par value Common Stock (the "Conversion Rate") for an aggregate of 66,667 shares. This Conversion Rate reflects the effect of the Reverse Stock Split. 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. At December 31, 2019 and 2018, after taking into account the effect of the Reverse Stock Split, the aggregate number of shares of Common Stock issuable upon conversion is 79,334 shares, which is the maximum number of shares issuable upon conversion.

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. The Preferred Stock does not vote with the Company's Common Stock on an as-converted basis on matters put before the Company's shareholders. However, the holders of the Preferred Stock have the right to approve specified matters as set forth in the certificate of designation and have the right to require the Company to repurchase the Preferred Stock in the event of a change of control, which has not been triggered as of December 31, 2019. 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 under the Securities Act of 1933, as amended, of the shares of common stock issuable upon conversion of the Preferred Stock.

13. SHAREHOLDERS' EQUITY

At-the-Market Offering

In January 2018, the Company entered into a common stock sales agreement with a financial institution pursuant to which the Company could offer and sell, through the sales agent, common stock representing an aggregate offering price of up to $2.5 million through an at-the-market continuous offering program. During the year ended December 31, 2018, the Company issued 128,853 shares of common stock at an average price of $14.10 for total net proceeds before offering expenses of approximately $1.8 million. Offering expenses, including broker fees and legal costs related to the at-the-market offering totaled $151 thousand. In January 2019, the Company terminated the at-the-market offering.

Warrants

In December 2016, the Company completed a registered direct offering of 100,000 shares of common stock at a net gross price of $15.00 per share. Concurrently, the investors received warrants to purchase 100,000 shares of common stock of the Company at an exercise price of $20.05 per share, subject to adjustment, for a period of five years from closing. The total net proceeds received by the Company were 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 have been classified as liabilities due to features in the warrant agreement that give the warrant holder an option to require the Company to redeem the warrant at a calculated fair value in the event of a "Fundamental Transaction," as defined in the warrant agreement. The fair value of the warrants was $73 thousand and $425 thousand at December 31, 2019 and December 31, 2018, respectively

As a result of common stock issuances made during the year ended December 31, 2018, the warrant exercise price was reduced from $20.50 to $11.30 per share pursuant to the original warrant agreement.

Stock Option Plans

From time to time, the Company may grant stock options under its incentive plan covering shares of common stock to employees of the Company. Stock options, when exercised, are settled through the payment of the exercise price in exchange for new shares of stock underlying the option. These awards typically expire ten years from the grant date.

Total stock-based compensation expense related to stock options was $41 thousand and $53 thousand for the year ended December 31, 2019 and 2018, respectively. As of December 31, 2019, all stock options had vested. During the year ended December 31, 2019, no stock options were granted, exercised or expired. As the result of an employee termination during the period, 500 unvested stock options were forfeited. For the year ended December 31, 2018, no stock options were granted, exercised or forfeited, however, 6,922 stock options expired during the period. Presented below is information about stock options outstanding and exercisable as of December 31, 2019 and December 31, 2018. All shares and prices per share have been adjusted for a one share-for-ten shares reverse stock split that took effect on January 6, 2020:

	2019		2018	
	Shares	Price (1)	Shares	Price (1)
Outstanding, beginning of year	32,046	$ 65.20	38,968	$ 80.50
Granted	-	-	-	-
Forfeited	(500)	11.60	-	-
Expired	-	-	(6,922)	151.20
Exercised	-	-	-	-
Outstanding, end of year	31,546	$ 66.10	32,046	$ 65.20
Exercisable, end of year	31,546	$ 66.10	26,546	$ 76.30

(1) Represents the weighted average price.

The following table summarizes information for stock options outstanding and for stock options exercisable at December 31, 2019. All shares and prices per share have been adjusted for a one share-for-ten shares reverse stock split that took effect on January 6, 2020:

Options Outstanding					Options Exercisable	
	Exercise Price					
	Range			Remaining		Weighted Average
Number of Shares	Low	High	Weighted Average	Contractual Term (years)	Number of Shares	Exercise Price
16,500	$ 7.20	$ 11.60	$ 10.00	7.8	16,500	$ 10.00
10,629	90.00	124.80	106.20	4.3	10,629	106.20
2,917	139.20	171.00	147.40	2.4	2,917	147.40
1,500	226.20	302.40	240.30	3.5	1,500	240.30
31,546	$ 7.20	$ 302.40	$ 66.10	5.9	31,546	$ 66.10

During the year ended December 31, 2019, the Company did not grant restricted or unrestricted shares to employees or directors. During the year ended December 31, 2018 the Company granted 48,516 unrestricted shares of common stock to employees and recorded $0.6 million of stock-based compensation expense. For the year ended December 31, 2019 there was no stock based compensation expense related to stock grants. For the year ended December 31, 2018 total stock-based compensation related to stock grants was $0.6 million. As of December 31, 2019, there was no unrecognized expense related to common stock grants.

14. INCOME TAXES

The Company incurred net losses for each of the years ended December 31, 2019 and 2018, 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:

	2019	2018
	(in thousands)	
Income tax benefit at federal statutory rate	$ (115)	$ 218
State income tax benefit, net of federal impact	(32)	37
Change in state tax rate, net of federal benefit	331	(435)
Change in value of warrant	(74)	163
Effect of Section 382 limitation	-	(1,303)
Percentage depletion carryover	9	4
Prior year true up	52	451
Other	23	50
Decrease in valuation allowance	(194)	815
Income tax benefit (expense)	$ -	$ -

The components of deferred tax assets and liabilities as of December 31, 2019 and 2018 are as follows:

	2019	2018
	(in thousands)	
Deferred tax assets:		
Net operating loss carryover (1)	$ 4,098	$ 3,594
Property and equipment	3,468	4,306
Percentage depletion and contribution carryovers (1)	1,833	1,721
Alternative minimum tax credit carryover (1)	42	42
Equity method investment and other	615	592
Deferred compensation liability	41	9
Asset retirement obligations	181	221
Stock-based compensation	68	61
Lease obligations	44	-
Total deferred tax assets	10,390	10,546
Deferred tax liabilities:		
Property and equipment	-	-
Lease assets	(40)	-
Other	-	-
Total deferred tax liabilities	(40)	-
Net deferred tax assets	10,350	10,546
Less valuation allowance	(10,350)	(10,546)
Net deferred tax asset	$ -	$ -

(1) In December 2017, the Company paid down debt through the issuance of common stock. This issuance represented a 49.3% ownership change in the Company. This change in ownership, combined with other equity events, triggered loss limitations under Internal Revenue Code ("I.R.C.") Section 382. As a result, the Company wrote-off $29.8 million of gross deferred tax assets in 2017, and an additional $2.4 million in gross deferred tax assets in 2018. Since the Company has maintained a valuation allowance against these tax assets there is no impact to the consolidated statement of operations in either year.

As of December 31, 2019, the Company has approximately $6.4 million of net operating loss carryovers (after limitations) for federal income tax purposes. The net operating losses are not subject to limitation under I.R.C. Section 382 and carry forward indefinitely.

I.R.C. Section 382 of the Internal Revenue Code limits the Company's ability to utilize the tax deductions associated with its oil and gas properties to offset taxable income in future years, due to the existence of a Net Unrealizable Built-In Loss ("NUBIL") at the time of the change in control. Such a limitation will be effective for a five-year period subsequent to the change in control. In the event the Company has Recognized Built-In Losses ("RBIL") during the five-year period, those losses will be limited; losses exceeding the annual limitation are carried forward as RBIL carryovers. As of December 31, 2019, the Company has approximately $7.1 million of RBIL carryovers, which carry forward indefinitely subject to the annual limitation.

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, 2019 and 2018, no adjustments were recognized for uncertain tax positions.

The Company files income tax returns in U.S. federal and multiple state jurisdictions. The Company is subject to tax audits in these jurisdictions until the applicable statute of limitations expires. The Company is no longer subject to U.S. federal tax examinations for tax years prior to 2016. The Company is open for various state tax examinations for tax years 2015 and later. The Company's policy is to recognize potential interest and penalties accrued related to uncertain tax positions within income tax expense. For the years ended December 31, 2019 and 2018, the Company did not recognize any interest or penalties in its statement of operations, nor did it have any interest or penalties accrued in its balance sheet at December 31, 2019 and 2018 related to uncertain tax positions.

15. LOSS PER SHARE

Basic net loss per common share is calculated by dividing net loss attributable to common shareholders by the weighted-average number of common shares outstanding for the respective period. Diluted net loss per common share is calculated by dividing adjusted net loss by the diluted weighted average number of common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of stock options and warrants, which are measured using the treasury stock method, the conversion feature of the Series A Preferred Stock, and unvested shares of restricted common stock. When the Company recognizes a net loss, as was the case for the years ended December 31, 2019 and 2018, all potentially dilutive shares are anti-dilutive and are consequently excluded from the calculation of dilutive net loss per common share.

The following table sets forth the calculation of basic and diluted net loss per share for the years ended December 31, 2019 and 2018 all shares and per share amounts have been adjusted for a one share-for-ten shares reverse stock split which took effect on January 6, 2020:

	2019	2018
	(in thousands except per share data)	
Net loss	$ (550)	$ (1,040)
Accrued dividend on Series A Preferred Stock	(372)	(329)
Net loss applicable to common shareholders	$ (922)	$ (1,369)
Basic weighted-average common shares outstanding	1,340	1,288
Dilutive effect of potentially dilutive securities	-	-
Diluted weighted-average common shares outstanding	1,340	1,288
Basic net loss per share	$ (0.69)	$ (1.06)
Diluted net loss per share	$ (0.69)	$ (1.06)

For the years ended December 31, 2019 and 2018, potentially dilutive securities excluded from the calculation of weighted average shares because they were anti-dilutive are as follows:

	2019	2018
	(in thousands)	
Stock options	31	32
Warrants	100	100
Series A Preferred Stock	79	79
Total	210	211

16. FAIR VALUE OF FINANCIAL INSTRUMENTS

The Company's fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the hierarchy level. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 - Quoted prices for identical assets and liabilities traded in active exchange markets.

Level 2 - Observable inputs other than Level 1 that are directly or indirectly observable for the asset or liability, including quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities inactive markets, or other observable inputs that can be 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.

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:

Warrant Valuation Methodologies

The warrants contain a dilutive issuance and other liability provisions that 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. There were no changes in the methodology to value the warrants during 2019. The Company worked with a third-party valuation expert estimating the value of the warrants at December 31, 2019 and 2018 using a Lattice model, with the following assumptions:

	2019	2018
Number of warrants outstanding	100,000	100,000
Expiration date	June 21, 2022	June 21, 2022
Exercise price	$ 11.30	$ 11.30
Stock price	$ 3.00	$ 6.70
Dividend yield	0%	0%
Average volatility rate	80%	90%
Risk free interest rate	1.59%	2.47%

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. As of December 31, 2019, and 2018, the fair value of the warrants was $73 thousand and $425 thousand, respectively.

Marketable Equity Securities Valuation Methodologies

The fair value of marketable equity securities is based on quoted market prices obtained from independent pricing services. The Company has an investment in the marketable equity securities of Anfield Energy ("Anfield"), which it acquired as consideration for sales of certain mining operations. Anfield is traded in an active market under the trading symbol AEC:TSXV and has been classified as Level 1. Prior to May 2019, the Company also had an investment in Sutter Gold Mining Company ("Sutter"). In May 2019, Sutter's secured lender made a demand for full repayment of Sutter's indebtedness and gave notice to enforce its security, thereby forcing Sutter into bankruptcy. As a result, the fair value of the Company's investment in the marketable equity securities of Sutter is $0.

	Anfield	Sutter
Number of shares owned	3,631,365	495,816
Quoted market price	$ 0.08	$ 0.00
Fair value	$ 306,868	$ -

Other Financial Instruments

The carrying amount of cash and equivalents, oil and natural gas sales receivable, other current assets, accounts payable and accrued expenses approximate fair value due to the short-term nature of those instruments. The recorded amount for the credit facility discussed in Note 9-*Debt*, as of December 31, 2018 also approximated its fair market value due to the variable nature of the interest rate.

Recurring Fair Value Measurements

Recurring measurements of the fair value of assets and liabilities as of December 31, 2019 and 2018 are as follows:

	December 31, 2019				December 31, 2018			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
		(in thousands)						
Assets:								
Marketable Equity Securities	307	-	-	307	533	3	-	536
Total	$ 307	$ -	$ -	$ 307	$ 533	$ 3	$ -	$ 536
Liabilities:								

Warrants	-	-	73	73	-	-	425	425
Total	$ -	$ -	$ 73	$ 73	$ -	$ -	$ 425	$ 425

The following table presents a reconciliation of our Level 3 warrants measured at fair value

	Year Ended December 31,	
	2019	2018
	(in thousands)	
Fair value of Level 3 instruments liabilities beginning of period	$ 425	$ 1,200
Net unrealized (gain) loss on warrant valuation	(352)	(775)
	-	
Fair value of Level 3 instruments liabilities end of period	$ 73	$ 425

17. SUPPLEMENTAL OIL AND NATURAL GAS INFORMATION (UNAUDITED)

Capitalized Costs incurred

The capitalized costs incurred in crude oil and natural gas acquisitions, exploration and development activities for the years ended December 31, 2019 and 2018 are highlighted in the table below:

	2019	2018
	(in thousands)	
Proved property acquisition	$ -	$ -
Unproved property acquisition	12	244
Development	305	39
Exploration	552	1,234
Total	$ 869	$ 1,517

Capitalized Costs

The following table presents the Company's capitalized costs associated with oil and natural gas producing activities as of December 31, 2019 and 2018:

	2019	2018
	(in thousands)	
Oil and Natural Gas Properties:		
Unevaluated properties:		
Unproved leasehold costs	$ 3,741	$ 3,728
Evaluated properties in full cost pool	89,113	88,764
Less accumulated depreciation, depletion and amortization	(84,400)	(83,729)
Net capitalized costs	$ 8,454	$ 8,763

The Company's depreciation, depletion and amortization was $671 thousand ($4.63 per BOE) and $368 thousand ($3.20 per BOE) for the years ended December 31, 2019 and 2018, respectively.

Unevaluated oil and natural gas properties consist of leasehold costs that are excluded from the depletion, depreciation and amortization calculation and the ceiling test until a determination about the existence of proved reserves can be completed. Unevaluated oil and natural gas properties consisted of unproved lease acquisition costs and costs paid to evaluate potential acquisition prospects of $3.7 million and $3.7 million at December 31, 2019 and 2018, respectively.

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. As a result of a transfer of acreage for working interest in wells drilled in South Texas, which was completed in May 2019, the Company revalued the remaining acreage held in the area and transferred unproved leasehold acreage of $0.4 million to the full cost pool. During 2018, the Company reclassified $0.7 million of unevaluated oil and natural gas properties to the full cost pool related to the drilling and completion of the J. Beeler No. 1 well in South Texas, which was completed in December 2018.

Results of Operations from oil and natural gas producing activities

Presented below are the results of operations from oil and natural gas producing activities for the years ended December 31, 2019 and 2018:

	2019	2018
	(in thousands)	
Oil and natural gas sales	$ 6,573	$ 5,539
Lease operating expense	(1,848)	(1,898)
Production taxes	(429)	(392)
Depreciation, depletion and amortization	(671)	(368)
Impairment of oil and natural gas properties	-	-
Results of operations from oil and natural gas producing activities	$ 3,625	$ 2,881

Oil and Natural Gas Reserves (Unaudited)

Proved reserves are estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Oil and natural 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 natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and natural gas reserve quantities at December 31, 2019 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Don Jacks, PE. Proved oil and natural gas reserve quantities at December 31, 2018 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Jane E. Trusty, PE. Both estimates have been prepared in accordance with guidelines established by the SEC. All of the Company's estimated proved reserves are located in the United States.

As of December 31, 2019, 2018 and 2017, the Company had no proved undeveloped reserves and all proved reserves were proved developed producing.

The Company's estimated quantities of proved oil and natural gas reserves and changes in net proved reserves are summarized below for the years ended December 31, 2019 and 2018:

	2019		2018	
	Oil (bbls)	Gas (mcfe) (1)	Oil (bbls)	Gas (mcfe) (1)
Total proved reserves:				
Reserve quantities, beginning of year	751,260	737,998	676,030	888,507
Revisions of previous estimates	99,352	511,969	88,956	58,177
Discoveries and extensions	72,907	101,892	61,277	78,007
Sale of minerals in place	(5,924)	(13,083)	-	-
Production	(110,090)	(209,518)	(75,003)	(286,692)
Reserve quantities, end of year	807,505	1,129,258	751,260	737,998

(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.

Notable changes in proved reserves for the year ended December 31, 2019 included the following:

- Discoveries and extensions of 89,889 BOE were primarily attributable to drilling in our South Texas properties**.**
- Revisions of previous estimates of 184,680 BOE were primarily attributable to revisions due to the performance of the J. Beeler well drilled in late 2018 in our South Texas properties.

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:

	2019	2018
Oil per Bbl	$ 55.69	$ 65.56
Gas per Mcfe (1)	$ 2.58	$ 3.10

(1) Consists of the weighted average price for natural gas in mcf plus NGLs 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% annual discount factor.

The standardized measure of discounted future net cash flows relating to the Company's proved oil and natural gas reserves is as follows as of December 31, 2019 and 2018:

	2019	2018
	(in thousands)	
Future cash inflows	$ 45,528	$ 49,457
Future cash outflows:		
Production costs	(21,435)	(23,648)
Development costs	-	-
Income taxes	(3,747)	(4,341)
Future net cash flows	20,436	21,468
10% annual discount factor	(9,998)	(9,869)
Standardized measure of discounted future net cash flows	$ 10,348	$ 11,599

Changes in Standardized Measure (Unaudited)

The changes in the standardized measure of future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2019 and 2018 are as follows:

	2019	2018
	(in thousands)	
Standardized measure, beginning of year	$ 11,599	$ 9,253
Sales of oil and natural gas, net of production costs	(4,296)	(3,235)
Net changes in prices and production costs	(2,499)	3,419
Changes in estimated future development costs	-	-
Extensions and discoveries	2,231	1,912
Sale of minerals in place	(83)	-
Revisions in previous quantity estimates	2,130	761
Previously estimated development costs incurred	-	-
Net changes in income taxes	(299)	(1,425)
Accretion of discount	1,068	925
Changes in timing and other	499	(11)
Standardized measure, end of year	$ 10,348	$ 11,599

18. SUBSEQUENT EVENTS

Reverse Stock Split

On January 6, 2020, pursuant to the Company's definitive proxy statement filed on November 5, 2019 for its Annual Meeting of Shareholders, the shareholders voted to approve an amendment to the Articles of Incorporation to implement a reverse stock split of the Company's outstanding common stock at a reverse split ratio of one share-for-ten shares. The reverse stock split which became effective on January 6, 2020, had no effect on the par value of the Common Stock and did not reduce the number of authorized shares, which is unlimited. It also did not affect the number of Series A Preferred Shares outstanding; however, it did reduce the conversion factor of the Company's Series A Convertible Preferred Stock.

The reason for the reverse stock split was to maintain the Company's listing on The Nasdaq Capital Market, which pursuant to Nasdaq Listing Rule 5550(a)(2)(the "Rule") requires that if the closing bid price of the Common Stock is below $1.00 for 30 consecutive trading days, then the closing bid price must be $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the Rule.

Acquisition of New Horizon Resources, LLC

On March 1, 2020, the Company acquired all of the issued and outstanding equity interests of New Horizon Resources, LLC ("New Horizon"), whose assets include acreage and operated producing properties in North Dakota (the "Properties"). The consideration paid at closing consisted of 59,498 shares of the Company's common stock which was valued at $275 thousand based on the 15-day volume adjusted weighted average price and $150 thousand in cash (the "Acquisition"). The New Horizon properties consist of approximately 1,300 net acres located primarily in McKenzie and Divide Counties, North Dakota, which are 100% held by production, average 63% working interest and produced approximately 30 net Boepd (88% oil) for the six-month period ended December 31, 2019. The company has preliminarily allocated the purchase price of the Acquisition to the assets and liabilities pending the completion of valuations of the proved oil and gas properties acquired as follows:

Preliminary provisional allocation of purchase price: (in thousands)

Fair value of net assets		
Receivables and other current assets	$	20
Deposit collateralizing surety bond		55
Proved oil and gas properties		433
Accounts payable and revenue suspense		(50)
Fair value of consideration paid for net assets	$	458
Cash consideration	$	150
Issuance of 59,498 shares of common stock at $4.62 per share		275
Less: balance of cash account acquired in acquisition		(27)
Add: long-term notes payable repaid at closing		60
Total fair value of consideration transferred	$	458

Sublease of Denver office

In January 2020, the Company entered into a sublease agreement for the remaining lease term of its Denver office lease, which expires on January 31, 2023. The sublease is effective as of March 1, 2020. The Company's undiscounted minimum lease obligation is $218 thousand of which, per the sublease agreement, the sublessee is obligated to pay $182 thousand.

Restricted share issuance

In January 2020, the Company's board of directors granted 48,000 restricted shares to the Chief Executive Officer, which vest equally over two years on January 28, 2021 and 2022. In addition, the Company's board of directors granted a total of 28,000 restricted shares to members of the board of directors which vest on January 28, 2021.

Decline in crude oil prices

In early March 2020, the NYMEX WTI crude oil price decreased significantly. Currently, we do not have any commodity derivative contracts in place to mitigate the effect of lower commodity prices on our revenues. Lower oil and natural gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce.

Lower crude prices could also affect the realizability of the Company's oil and gas properties. In the calculation of the ceiling test for the year ended December 31, 2019, the Company used $55.69 per barrel for oil and $2.58 per mcf for natural gas (as further adjusted for differentials related to 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%. As of March 20, 2020, the WTI spot price for crude oil was $23.64 and the 12-month strip price was $28.44. To determine the extent of these price reductions on the realizability of the Company's oil and gas properties, the Company reran the year end reserves using 50% of the average crude price used in the original ceiling test calculation, or $27.85, as further adjusted for differentials, and determined that by using that price the Company would have incurred a ceiling test write-down of approximately $1.7 million.

COVID-19

In early March 2020, there was a global outbreak of COVID-19 that has resulted in changes in global supply and demand of certain mineral and energy products including crude oil. These changes, including a potential economic downturn and any potential resulting direct and indirect negative impact to the Company cannot be determined, but they could have a prospective material impact to the Company's operations, cash flows, and liquidity.

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*	Amended and Restated Articles of Incorporation
3.2**	Amended and Restated Bylaws, dated as of August 5, 2019 (incorporated by reference from Exhibit 3.1 to the Company's Form 8-K filed August 9, 2019)
3.3*	Certificate of Designation for Series A Convertible Preferred Stock (incorporated by reference from Exhibit A to Exhibit 3.1 to this Annual Report on Form 10-K)
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**†	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)
10.2**†	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)
10.3**	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)
10.4**†	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)
10.5**†	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)
10.5.1**	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)
10.6(a)**†	Executive Employment Agreement – Ryan Smith (effective 3-5-20) (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed March 10, 2020)
10.6(b)**†	Form of Option Agreement between U.S. Energy Corp. and its directors (incorporated by reference from Exhibit 10.8(i) to the Company's Annual Report on Form 10-K filed March 28, 2018)
10.6(c)**†	Form of Incentive Option Agreement between U.S. Energy Corp. and its executive officers (incorporated by reference from Exhibit 10.8(j) to the Company's Annual Report on Form 10-K filed March 28, 2018)
10.6(d)**†	Form of Indemnity Agreement between U.S. Energy Corp. and its directors and officers (incorporated by reference from Exhibit 10.8(k) to the Company's Annual Report on Form 10-K filed March 28, 2018)
10.7**	Series A Convertible Preferred Stock Purchase Agreement between the Company and Mt. Emmons Mining Company dated February 11, 2016 (incorporated by reference from Exhibit 10.1 to the Current Report on Form 8-K filed February 12, 2016)
10.8**	Investor Rights Agreement between the Company and Mt. Emmons Mining Company dated February 11, 2016 (incorporated by reference from Exhibit 10.2 to the Current Report on Form 8-K filed February 12, 2016)
10.9**	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)
10.10**	Final Release and Settlement Agreement among U.S. Energy Corp. and Energy One, LLC, and APEG Energy II, LP, APEG Energy II GP, LLC and John Hoffman, dated May 22, 2019 (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed on May 24, 2019)

10.11**	Membership Interest Purchase Agreement dated March 1, 2020 by and among U.S. Energy Corp, as Buyer, and Donald A. Kessel and Robert B. Foss, as Sellers (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed on March 5, 2020)
14.1**	Code of Ethics and Conduct (incorporated by reference from Exhibit 14.1 to the Company's Form 8-K filed August 5, 2019)
21.1*	Subsidiaries of Registrant
23.1*	Consent of Independent Registered Accounting Firm (Plante & Moran, PLLC)
23.2*	Consent of Reserve Engineer (Don Jacks, PE)
23.3*	Consent of Reserve Engineer (Jane E. Trusty, PE)
31.1*	Certification of Chief Executive Officer and principal financial officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002
32.1*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Reserve Report Summary (Don Jacks, 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 30, 2020	By: */s/ Ryan L. Smith* RYAN L. SMITH, President, Chief Executive Officer, Chief Financial Officer (as Principal Executive, Financial and Accounting 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 30, 2020	By: */s/ James W. Denny* James W. Denny, Director
Date: March 30, 2020	By: */s/ Patrick E. Duke* Patrick E. Duke, Director
Date: March 30, 2020	By: */s/ Randall D. Keys* Randall D. Keys, Director
Date: March 30, 2020	By: */s/ Javier F. Pico* JAVIER F. PICO, Director
Date: March 30, 2020	By: */s/ D. Stephen Slack* D. Stephen Slack, Director