SECURITIES & EXCHANGE COMMISSION EDGAR FILING

US ENERGY CORP

Form: 10-K

Date Filed: 2021-03-26

Corporate Issuer CIK: 101594

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, 2020

[ ] **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 (State or other jurisdiction of incorporation or organization)	**83-0205516** (I.R.S. Employer Identification No.)
675 Bering, Suite 390, Houston, Texas (Address of principal executive offices)	**77057** (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 LLC (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 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 [X]

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. [ ]

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, 2020, was $4,187,393. For purposes of calculating the aggregate market value of shares held by non-affiliates, we have assumed that all outstanding shares are held by non-affiliates, except for shares held by each of our executive officers, directors and 5% or greater shareholders. In the case of 5% or greater shareholders, we have not deemed such shareholders to be affiliates unless there are facts and circumstances which would indicate that such shareholders exercise any control over our company, or unless they hold 10% or more of our outstanding common stock. These assumptions should not be deemed to constitute an admission that all executive officers, directors and 5% or greater shareholders are, in fact, affiliates of our company, or that there are not other persons who may be deemed to be affiliates of our company. Further information concerning shareholdings of our officers, directors and principal shareholders is included or incorporated by reference in Part III, Item 12 of this Annual Report on Form 10-K.

The Registrant had 4,676,301 shares of its $0.01 par value common stock outstanding as of March 22, 2021.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement relating to its 2021 annual meeting of shareholders (the "2021 Proxy Statement") are incorporated by reference into Part III of this Annual Report on Form 10-K where indicated. The 2021 Proxy Statement will be filed with the U.S. Securities and Exchange Commission within 120 days after the end of the fiscal year to which this report relates.

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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, Section 21E of the Securities Exchange Act of 1934, as amended, and the Private Securities Litigation Reform Act of 1995. 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;
- 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;
- future cash flows, expenses and borrowings;
- pursuit of potential acquisition opportunities;
- economic downturns and possible recessions caused thereby (including as a result of COVID-19);
- the effects of global pandemics, such as COVID-19 on our operations, properties, the market for oil and gas, and the demand for oil and gas;
- 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 discussed below under “Summary of Risk Factors”, and under “Risk Factors”, below.

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.

All forward-looking statements speak only at the date of the filing of this Annual Report. We do not undertake any obligation to update or revise publicly any forward-looking statements except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Summary Risk Factors

An investment in our securities involves a high degree of risk. You should carefully consider the risks summarized below. These risks include, but are not limited to, the following:

- 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;

- economic downturns and possible recessions caused thereby (including as a result of COVID-19);

- the effects of global pandemics, such as COVID-19 on our operations, properties, the market for oil and gas, and the demand for oil and gas;

- the need to write-down assets and/or shut-in wells, or our non-operated wells being shut-in by their operators;

- litigation involving our former officers and directors, shareholders and third parties;

- 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; and

- Other risks disclosed below under “Risk Factors”.

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.

API. The American Petroleum Institute gravity, or API gravity, is a measure of how heavy or light a petroleum liquid is compared to water: if its API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier and sinks.

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.

Bopd. Barrels of per oil 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.

NGL. Natural gas liquids.

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 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.

WTI. West Texas Intermediate.

General Information

In this Annual Report on Form 10-K, we may rely on and refer to information regarding the oil and gas industry in general from market research reports, analyst reports and other publicly available information. Although we believe that this information is reliable, we cannot guarantee the accuracy and completeness of this information, and we have not independently verified any of it.

Our fiscal year ends on December 31st. Interim results are presented on a quarterly basis for the quarters ended March 31, June 30, and September 30th, the first quarter, second quarter and third quarter, respectively, with the quarter ending December 31st being referenced herein as our fourth quarter. Fiscal 2020 means the year ended December 31, 2020, whereas fiscal 2019 means the year ended December 31, 2019.

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”), which has been retroactively reflected throughout this Report.

Unless the context requires otherwise, references to the “Company,” “we,” “us,” “our,” “U.S. Energy,” and “U.S. Energy Corp.” refer specifically to U.S. Energy Corp. and its consolidated subsidiaries.

In addition, unless the context otherwise requires and for the purposes of this Report only:

- “Exchange Act” refers to the Securities Exchange Act of 1934, as amended;
- “SEC” or the “Commission” refers to the United States Securities and Exchange Commission; and
- “Securities Act” refers to the Securities Act of 1933, as amended.

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 on the Gulf Coast of Texas, South Texas, Southeastern New Mexico, Wyoming 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 primarily 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. During the year ended December 31, 2020, we acquired operated properties in the Williston Basin, North Dakota, the Texas Gulf Coast, the Permian Basin in New Mexico and the Powder River Basin in Wyoming.

Office Location and Website

Our principal executive office is located at 675 Bering, Suite 390, Houston, Texas 77057. Our telephone number is (303) 993-3200.

We file annual, quarterly, and current reports, proxy statements and other information with the SEC. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC like us at https://www.sec.gov (our filings can be found at https://www.sec.gov/cgi-bin/browse-edgar?action=getcompany&CIK=0000101594) and on the “Investors – SEC Filings” page of our website at https://usnrg.com. Copies of documents filed by us with the SEC are also available from us without charge, upon oral or written request to our Secretary, who can be contacted at the address and telephone number set forth on the cover page of this Report. 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 Report.

Oil and Natural Gas Operations

During 2020 we actively pursued acquisitions of exploration, development and production-stage oil and natural gas properties or companies resulting in three separate acquisitions of operated and non-operated properties. We participate in oil and natural gas projects as both a non-operating working interest owner through exploration and development agreements with various oil and natural gas exploration and production companies and as an operator. 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 1,255,236 BOE (78% oil and 22% natural gas) as of December 31, 2020, with a standardized measure value of $8.6 million.
- As of December 31, 2020, our oil and natural gas leases covered 90,136 gross acres and 6,064 net acres.
- 134 gross (30.7 net) producing wells as of December 31, 2020.

- 218 BOE per day average net production for 2020.

Acquisition of Operated Properties

During 2020 we acquired operated properties in the Williston Basin, North Dakota, the Permian Basin in New Mexico, the Powder River Basin in Wyoming and in the Gulf Coast of Texas. Although production from the operated properties was only 4,598 BOE during 2020, they represented $3.7 million, or 42.6% of the PV-10 related to our oil and gas reserves at December 31, 2020. The operated properties have an average working interest of approximately 96% and an average net revenue interest of 81%.

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, New Mexico 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 comprised approximately 25.1% of the PV-10 related to our oil and natural gas reserves at December 31, 2020.

Permian Basin, New Mexico

Cimarex Energy Company. During 2020 we acquired an interest in three wells Cimarex Energy Company operates in Lea County, New Mexico. We currently hold a 43.8% working interest and a 36.3% net revenue interest in these wells. All of the leases are currently held by production and comprised approximately 15.3% of the PV-10 related to our oil and natural gas reserves at December 31, 2020.

Texas (Gulf Coast)

Contango Resources Inc. We have an interest in multiple wells with Contango Resources 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 comprised approximately 5.5% of the PV-10 related to our oil and natural gas reserves at December 31, 2020.

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.

Previously, 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 the 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 the 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, in December 2017 the BLM finalized a rule 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 our activities and those 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 activities and those of 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 in its 2019 World Energy Outlook report 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. While the United States withdrew from the Paris Agreement in in November 2020 under then President Trump, President Biden has since taken action for the United States to rejoin the Paris Agreement. Separately, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. 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 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 operator’s and control of well insurance for our oil and natural gas operations and 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, 2020, we had 2 full-time employees. We utilized several consultants on an as-needed basis during 2020.

Forward Plan

In 2021 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. In addition, we plan to grow production by performing workovers on operated idle wells acquired in 2020 to return them back to production.

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.

In early March 2020, there was an outbreak of a novel strain of coronavirus, which causes the infectious disease known as COVID-19, which resulted in a drastic decline in global demand of certain mineral and energy products including crude oil. As a result of the lower demand caused by the COVID-19 pandemic and the oversupply of crude oil, spot and future prices of crude oil fell to historic lows during the second quarter of 2020, which remained depressed for the majority of 2020. Operators in North Dakota’s Williston Basin responded by significantly decreasing drilling and completion activity and shutting in or curtailing production from a significant number of producing wells, all of which have since come back online. Operators decisions on these matters are changing rapidly and it is difficult to predict the future effects on the Company’s business. 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.

Additionally, the outbreak of COVID-19 and decreases in commodity prices resulting from oversupply, government-imposed travel restrictions, and other constraints on economic activity have caused a significant decrease in the demand for oil and has created disruptions and volatility in the global marketplace for oil and gas which began in the first quarter of 2020, and continued through most of 2020, which negatively affected our results of operations and cash flows. While demand and commodity prices have recently recovered and are back to pre-pandemic levels, our financial results may continue to be depressed in future quarters. The extent to which the COVID-19 pandemic impacts our business going forward will depend on numerous evolving factors we cannot reliably predict, including the duration and scope of the pandemic; governmental, business, and individuals’ actions in response to the pandemic; the availability and efficacy of vaccines; and the impact on economic activity including the possibility of recession or financial market instability. These factors may adversely impact the supply and demand for oil and gas and our ability to produce and transport oil and gas and perform operations at and on our properties. This uncertainty also affects management’s accounting estimates and assumptions, which could result in greater variability in a variety of areas that depend on these estimates and assumptions, including investments, receivables, and forward-looking guidance.

Development

Until acquiring operated properties during 2020, we primarily engaged 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.

During 2020, we acquired operated interests in several wells in North Dakota, New Mexico, Wyoming, and the Texas Gulf Coast. Beginning in December 2020 and throughout 2021, our development efforts will be focused on returning idle wells to production.

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 sold at prices tied to the spot oil markets. Our natural gas production is sold under short-term contracts and priced based on first-of-the-month index prices or on daily spot market prices. For our non-operated production, 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 our drilling and producing activities and other oil and natural gas operations and those of our operating partners. 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 operations and those of our operating partners.

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.

Recent Developments

On February 11, 2021, we sold 1,131,500 shares of our common stock in an underwritten offering at a public offering price of $5.10 per share (the "Offering") . The Offering closed on February 17, 2021. The net proceeds to us from the Offering, after deducting the underwriting discounts and commissions and Offering expenses, were $5.3 million. We intend to use the net proceeds from the offering for general corporate purposes, capital expenditures, working capital, and potential acquisitions of oil and gas properties.

On March 4, 2021 we entered into a Debt Conversion Agreement with APEG Energy II, L.P. ("APEG II") beneficially owned by our former director, Patrick E. Duke. Pursuant to the Debt Conversion Agreement, APEG II converted a total of approximately $413,000, representing the principal amount of the Secured Promissory Note of $375,000 and accrued interest of approximately $38,000 into 97,962 unregistered shares of our common stock. The number of shares was based on a conversion price of $4.21 per share, a 9.9% discount to the ten-day volume weighted average price of our common stock for the ten days immediately preceding the signing of the Debt Conversion Agreement (the "Discounted VWAP").

Also, on March 4, 2021, APEG II entered into a Subscription Agreement with us, whereby APEG II subscribed to purchase 90,846 unregistered shares of our common stock for an aggregate of approximately $383,000 based on the Discounted VWAP. The $383,000 subscription price was paid by way of forgiveness by APEG II of the same amount of funds owed by us for reimbursement of APEG II's legal costs in connection with certain shareholder derivative actions brought by APEG II against us and our former Chief Executive Officer in Colorado and Texas, which were dismissed in May 2020 and August, respectively.

On March 9, 2021, we entered into a commodity derivative contract to fix the price of 100 barrels of crude oil per day from March 1 to December 31, 2021 at $61.90 based on the calendar month average of WTI Crude Oil.

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 Related to the Oil and Natural Gas Industry and Our Business

We may need additional capital to complete future acquisitions, conduct our operations, and fund our business, and our ability to obtain the necessary funding is uncertain.

We may need to raise additional funding to complete future potential acquisitions and will be required to raise additional funds through public or private debt or equity financing or other various means to fund our operations and complete workovers and acquire assets. In such a case, adequate funds may not be available when needed or may not be available on favorable terms. If we need to raise additional funds in the future by issuing equity securities, dilution to existing stockholders will result, and such securities may have rights, preferences, and privileges senior to those of our common stock. If funding is insufficient at any time in the future and we are unable to generate sufficient revenue from new business arrangements, to complete future acquisitions or operations, our results of operations and the value of our securities could be adversely affected.

Additionally, due to the nature of oil and gas interests, i.e., that rates of production generally decline over time as oil and gas reserves are depleted, if we are unable to acquire additional properties and/or develop our reserves, either because we are unable to raise sufficient funding for such development activities, or otherwise, or in the event we are unable to acquire additional operated or non-operated properties, we believe that our revenues will continue to decline over time. Furthermore, in the event we are unable to raise additional required funding in the future, we will not be able to participate in the drilling of additional wells, will not be able to complete other drilling and/or workover activities.

If this were to happen, we may be forced to scale back our business plan which could result in the value of our outstanding securities declining in value.

Oil, natural gas liquids (NGL) and natural gas prices, are volatile and declines in the prices of such commodities have in the past, and will continue in the future to, adversely affect our business, financial condition or results of operations, and our ability to meet our capital expenditure obligations or targets and financial commitments.

The price of oil and, to a lesser extent, natural gas and NGLs, heavily influences our revenue, profitability, cash flows, liquidity, access to capital, present value and quality of our reserves, the nature and scale of our operations, and our future rate of growth. Oil, NGL, and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. In recent years, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other. The price of crude oil has experienced significant volatility over the last five years, with the price of a barrel of oil dropping below $20 during the early part of 2020, due in part to reduced global demand stemming from the recent global COVID-19 outbreak, and only recently increasing to around $55-65 a barrel. A prolonged period of low market prices for oil and natural gas, or further declines in the market prices for oil and natural gas, will likely result in capital expenditures being further curtailed and will adversely affect our business, financial condition and liquidity. Additionally, lower oil and natural gas prices have, and may in the future, cause, a decline in our stock price. During the year ended December 31, 2019, the daily Cushing, Oklahoma West Texas Intermediate ("WTI") oil spot price ranged from a high of $66.24 per barrel (Bbl) to a low of $46.31 per Bbl and the NYMEX natural gas Henry Hub spot price ranged from a high of $4.25 per one million British Thermal Units (MMBtu) to a low of $1.75 per MMBtu. During the year ended December 31, 2020, the daily WTI oil spot price ranged from a high of $63.27 per Bbl to a low of ($36.98) per Bbl and the NYMEX natural gas Henry Hub spot price ranged from a high of $3.14 per MMBtu to a low of $1.33 per MMBtu.

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.

As described above, oil, NGLs, and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. An extended period of continued lower oil prices, or additional price declines, will have further adverse effects on us. The prices we receive for any future production and the prices received from operators of our NAPA non-operated production, and the levels of such production, will continue to depend on numerous factors, including the following:

- the domestic and foreign supply of oil, NGLs, and natural gas;
- the domestic and foreign demand for oil, NGLs, and natural gas;
- the prices and availability of competitors' supplies of oil, NGLs, and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and state-controlled oil companies relating to oil price and production controls;
- the price and quantity of foreign imports of oil, NGLs, and natural gas;
- the impact of U.S. dollar exchange rates on oil, NGLs, and natural gas prices;
- domestic and foreign governmental regulations and taxes;
- speculative trading of oil, NGLs, and natural gas futures contracts;
- localized supply and demand fundamentals, including the availability, proximity, and capacity of gathering and transportation systems for natural gas;
- the availability of refining capacity;
- the prices and availability of alternative fuel sources;
- the threat, or perceived threat, or results, of viral pandemics, for example, as currently being experienced with the COVID-19 pandemic;
- weather conditions and natural disasters;
- political conditions in or affecting oil, NGLs, and natural gas producing regions, including the Middle East and South America;
- the continued threat of terrorism and the impact of military action and civil unrest;

- public pressure on, and legislative and regulatory interest within, federal, state, and local governments to stop, significantly limit, or regulate hydraulic fracturing activities;
- the level of global oil, NGL, and natural gas inventories and exploration and production activity;
- authorization of exports from the United States of liquefied natural gas;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption; and
- overall worldwide economic conditions.

Declines in oil, NGL, or natural gas prices will reduce not only our revenue but also the amount of oil, NGL, and natural gas that we, and the operators of our properties, can produce economically. Should natural gas, NGL or oil prices decline in the future, our non-operated wells and/or any of our own wells, may be forced to be shut-in, and exploration and development plans for prospects and exploration or development activities may need to be postponed or abandoned. As a result, we may have to make substantial downward adjustments to our estimated proved reserves, each of which would have a material adverse effect on our business, financial condition, and results of operations.

The operators of our Williston Basin wells previously temporarily shut-in such wells to preserve oil and gas reserves for production during a more favorable oil price environment, and while such wells have resumed production, our wells may again be shut-in, should market conditions significantly deteriorate.

In early March 2020, there was a global outbreak of COVID-19 that resulted in a drastic decline in global demand of certain mineral and energy products including crude oil. As a result of the lower demand caused by the COVID-19 pandemic and the oversupply of crude oil, spot and future prices of crude oil fell to historic lows during the second quarter of 2020. Operators in North Dakota's Williston Basin (including the operators of our wells) responded by significantly decreasing drilling and completion activity and shutting in or curtailing production from a significant number of producing wells. Operators decisions on these matters are changing rapidly and it is difficult to predict the future effects on the Company's business. 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, and ability to finance planned capital expenditures. While our producing wells are shut-in, we do not generate revenues from such wells, and would need to use our cash on hand and funds we receive from borrowings and the sale of equity in order to pay our operating expenses. A continued period of low-priced oil may make it non-economical for our wells to operate, which would have a material adverse effect on our operating results and the value of our assets. We cannot estimate the future price of oil, and as such cannot estimate, when our wells may again be shut-in by their operators.

Our business and operations have been adversely affected by, and are expected to continue to be adversely affected by, the COVID-19 pandemic, and may be adversely affected by other similar outbreaks.

As a result of the COVID-19 pandemic or other adverse public health developments, including voluntary and mandatory quarantines, travel restrictions, and other restrictions, our operations, and those of our subcontractors, customers, and suppliers, have and are anticipated to continue to experience delays or disruptions and temporary suspensions of operations. In addition, our financial condition and results of operations have been and are likely to continue to be adversely affected by the COVID-19 pandemic.

The timeline and potential magnitude of the COVID-19 outbreak are currently unknown. The continuation or amplification of this virus could continue to more broadly affect the United States and global economy, including our business and operations, and the demand for oil and gas. For example, the outbreak of coronavirus has resulted in a widespread health crisis that will adversely affect the economies and financial markets of many countries, resulting in an economic downturn that will affect our operating results. Other contagious diseases in the human population could have similar adverse effects. In addition, the effects of COVID-19 and concerns regarding its global spread have recently negatively impacted the domestic and international demand for crude oil and natural gas, which has contributed to price volatility, impacted the price we receive for oil and natural gas, and has materially and adversely affected the demand for and marketability of our production, and is anticipated to continue to adversely affect the same for the foreseeable future. As the potential impact from COVID-19 is difficult to predict, the extent to which it will negatively affect our operating results, or the duration of any potential business disruption is uncertain. The magnitude and duration of any impact will depend on future developments and new information that may emerge regarding the severity and duration of COVID-19 and the actions taken by authorities to contain it or treat its impact, all of which are beyond our control.

Declining general economic, business or industry conditions have, and will continue to have, a material adverse effect on our results of operations, liquidity, and financial condition, and are expected to continue having a material adverse effect for the foreseeable future.

Concerns over global economic conditions, the threat of pandemic diseases and the results thereof, energy costs, geopolitical issues, inflation, the availability and cost of credit, the United States mortgage market, and a declining real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil and natural gas, declining business and consumer confidence, and increased unemployment, have precipitated an economic slowdown and a recession, which could expand to a global depression. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices and are expected to continue having a material adverse effect for the foreseeable future. If the economic climate in the United States or abroad continues to deteriorate, demand for petroleum products could diminish, which could further impact the price at which our operators can sell oil, natural gas, and natural gas liquids, affect the ability of our vendors, suppliers and customers to continue operations, and ultimately adversely impact our results of operations, liquidity and financial condition to a greater extent than it has already.

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, working over 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, workover 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 the majority of our properties, and therefore have limited ability to control the manner in which drilling and other exploration and development activities on our non-operated properties are conducted, which may increase these risks.

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 2020, our weighted average realized oil price in the Williston Basin was $32.63, which due to transportation costs was approximately $6.60 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.

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 2021 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.

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 shale formations are subject to risks related to horizontal drilling and completion techniques.

Operations in shale formations 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 shale 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.

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 the drilling prospects in South Texas 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 represents 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, 2020, 89% of our estimated proved reserves were developed producing and 11% were developed non-producing. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, volumetric analysis or probabilistic methods, in contrast to the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations.

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. For example, on March 9, 2021, we entered into a commodity derivative contract to fix the price of 100 barrels of crude oil per day from March 1 to December 31, 2021 at $61.90, based on the calendar month average of WTI Crude Oil. 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, New Mexico, the Texas Gulf Coast 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, New Mexico, the Texas Gulf Coast 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 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.

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.

Improvements in or new discoveries of alternative energy technologies could have a material adverse effect on our financial condition and results of operations.

Because our operations depend on the demand for oil and used oil, any improvement in or new discoveries of alternative energy technologies (such as wind, solar, geothermal, fuel cells and biofuels) that increase the use of alternative forms of energy and reduce the demand for oil, gas and oil and gas related products could have a material adverse impact on our business, financial condition and results of operations.

Competition due to advances in renewable fuels may lessen the demand for our products and negatively impact our profitability.

Alternatives to petroleum-based products and production methods are continually under development. For example, a number of automotive, industrial and power generation manufacturers are developing alternative clean power systems using fuel cells or clean-burning gaseous fuels that may address increasing worldwide energy costs, the long-term availability of petroleum reserves and environmental concerns, which if successful could lower the demand for oil and gas. If these non-petroleum-based products and oil alternatives continue to expand and gain broad acceptance such that the overall demand for oil and gas is decreased it could have an adverse effect on our operations and the value of our assets.

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.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, waste disposal, oil spills, seismic activity, climate change, explosions of natural gas transmission lines and the development and operation of pipelines and other midstream facilities may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Additionally, environmental groups, landowners, local groups and other advocates may oppose our operations through organized protests, attempts to block or sabotage our operations or those of our midstream transportation providers, intervene in regulatory or administrative proceedings involving our assets or those of our midstream transportation providers, or file lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business or those of our midstream transportation providers. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

Recently, activists concerned about the potential effects of climate change have directed their attention towards 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 energy-related activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities.

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 significantly upon the continued involvement of our present management.

We depend to a significant degree upon the involvement of our management, specifically, our Chief Executive Officer and Chief Financial Officer, Ryan L. Smith.

Our performance and success are dependent to a large extent on the efforts and continued employment of Mr. Smith. We do not believe that Mr. Smith could be quickly replaced with personnel of equal experience and capabilities, and his successor(s) may not be as effective. If Mr. Smith or any of our other key personnel resign or become unable to continue in their present roles and if they are not adequately replaced, our business operations could be adversely affected. The Company entered into an agreement with Mr. Smith on March 5, 2020. The term of Mr. Smith's Employment Agreement commenced on March 5, 2020, and was to continue until January 1, 2021, provided that on January 1, 2021, the Employment Agreement automatically renewed for one successive term of one year, until January 1, 2022.

We have an active Board of Directors that meets several times throughout the year and is intimately involved in our business and the determination of our operational strategies. Members of our Board of Directors work closely with management to identify potential prospects, acquisitions, and areas for further development. If any of our directors resign or become unable to continue in their present role, it may be difficult to find replacements with the same knowledge and experience and as a result, our operations may be adversely affected.

Our oil and natural gas reserves are estimated and may not reflect the actual volumes of oil and natural gas we will receive, and significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating accumulations of oil and natural gas is complex and is not exact, due to numerous inherent uncertainties. The process relies on interpretations of available geological, geophysical, engineering, and production data. The extent, quality, and reliability of this technical data can vary. The process also requires certain economic assumptions related to, among other things, oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds. The accuracy of a reserves estimate is a function of:

- the quality and quantity of available data;

- the interpretation of that data;
- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions.

The accuracy of any estimates of proved reserves generally increases with the length of the production history. Due to the limited production history of our properties, the estimates of future production associated with these properties may be subject to greater variance to actual production than would be the case with properties having a longer production history. As our wells produce over time and more data is available, the estimated proved reserves will be re-determined on at least an annual basis and may be adjusted to reflect new information based upon our actual production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

Actual future production, oil, and natural gas prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas most likely will vary from our estimates. It is possible that future production declines in our wells may be greater than we have estimated. Any significant variance to our estimates could materially affect the quantities and present value of our reserves.

We may purchase oil and natural gas properties with liabilities or risks that we did not know about or that we did not assess correctly, and, as a result, we could be subject to liabilities that could adversely affect our results of operations.

Before acquiring oil and natural gas properties, we estimate the reserves, future oil and natural gas prices, operating costs, potential environmental liabilities, and other factors relating to the properties. However, our review involves many assumptions and estimates, and their accuracy is inherently uncertain. As a result, we may not discover all existing or potential problems associated with the properties we buy. We may not become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We generally do not perform inspections on every well or property, and we may not be able to observe mechanical and environmental problems even when we conduct an inspection. The seller may not be willing or financially able to give us contractual protection against any identified problems, and we may decide to assume environmental and other liabilities in connection with the properties we acquire. If we acquire properties with risks or liabilities we did not know about or that we did not assess correctly, our business, financial condition, and results of operations could be adversely affected as we settle claims and incur cleanup costs related to these liabilities.

<u>Risks Related to Our Financial Statements</u>

We have written down, and may in the future be forced to further write-down, material portions of our assets due to low oil prices.

The successful efforts method of accounting is used for oil and gas exploration and production activities. Under this method, all costs for development wells, support equipment and facilities, and proved mineral interests in oil and gas properties are capitalized. We review the carrying value of our long-lived assets annually or whenever events or changes in circumstances indicate that the historical cost-carrying value of an asset may no longer be appropriate. We assess the recoverability of the carrying value of the asset by estimating the future net undiscounted cash flows expected to result from the asset, including eventual disposition. If the future net undiscounted cash flows are less than the carrying value of the asset, an impairment loss is recorded equal to the difference between the asset's carrying value and estimated fair value. This impairment does not impact cash flows from operating activities but does reduce earnings and our shareholders' equity.

Under the full cost method of accounting, we capitalize the cost to acquire, explore for and develop our oil and natural gas investments. 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 2020, our capitalized costs for oil and natural gas properties exceeded the ceiling and, therefore, we recorded an aggregate ceiling test write-down of $2.9 million. 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, 2020, we used an average price applicable to our properties of $39.57 per barrel for oil and $1.99 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.

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. The COVID-19 pandemic has led to an economic downturn resulting in lower oil prices which required us to incur material write-downs. Unevaluated properties not subject to depreciation, depletion and amortization amounted to an aggregate of approximately $1.6 million as of December 31, 2020. 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. During 2020 we impaired $2.1 million of unevaluated properties and reclassified these amounts to the full cost pool.

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, 2019 and 2020. 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, 2020 due to the material weaknesses described below.

As of December 31, 2020, we have identified the following material weaknesses:

- We had inadequate segregation of duties as a result of limited accounting staff and resources, which may impact our ability to prevent or detect material errors in our consolidated financial statements.
- We had inadequate segregation of duties related to logical access to our accounting systems, which may affect our ability to prevent or detect material errors in the recorded transactions.

As a result, our management also concluded that our disclosure controls and procedures were not effective as of December 31, 2020, 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.

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. A control deficiency exists when the design or operation of a control does not allow management or employees, in the normal course of performing their assigned functions, to prevent or detect misstatements on a timely basis.

Maintaining effective disclosure controls and procedures and effective internal control over financial reporting are necessary for us to produce reliable financial statements and the Company is committed to remediating its material weaknesses in such controls as promptly as possible. However, there can be no assurance as to when these material weaknesses will be remediated or that additional material weaknesses will not arise in the future. Any failure to remediate the material weaknesses, or the development of new material weaknesses in our internal control over financial reporting, could result in material misstatements in our financial statements and cause us to fail to meet our reporting and financial obligations, which in turn could have a material adverse effect on our financial condition and the trading price of our common stock, and/or result in litigation against us or our management. In addition, even if we are successful in strengthening our controls and procedures, those controls and procedures may not be adequate to prevent or identify irregularities or facilitate the fair presentation of our financial statements or our periodic reports filed with the SEC.

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 not be detected.

Our ability to use net operating loss carryforwards and realize 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.

Risks Related to Governmental Regulations

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.

Proposed changes to U.S. tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations, and cash flows.

From time to time, legislative proposals are made that would, if enacted, result in the elimination of the immediate deduction for intangible drilling and development costs, the elimination of the deduction from income for domestic production activities relating to oil and gas exploration and development, the repeal of the percentage depletion allowance for oil and gas properties, and an extension of the amortization period for certain geological and geophysical expenditures. Such changes, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and gas exploration and development, could adversely affect our business, financial condition, results of operations, and cash flows.

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.

Risks Related to Our Stock

We currently have an unlimited number of shares of common stock authorized and there may be future issuances of sales of our common stock, which could adversely affect the market price of our common stock and dilute a shareholder's ownership of common stock.

The exercise of (a) any options granted to executive officers and other employees under our equity compensation plans and (b) of any warrants and other issuances of our common stock could have an adverse effect on the market price of the shares of our common stock. Additionally, other than restrictions under our February 2021 underwriting agreement, we are not restricted from issuing additional shares of common stock, including any securities that are convertible into or exchangeable for, or that represent the right to receive shares of common stock, and currently have an unlimited number of authorized shares of common stock, provided that we are subject to the requirements of The NASDAQ Capital Market ("NASDAQ")(which generally requires shareholder approval for any transactions which would result in the issuance of more than 20% of our then outstanding shares of common stock or voting rights representing over 20% of our then outstanding shares of stock). Issuances of a substantial number of shares of our common stock and/or sales of a substantial number of shares of our common stock in the public market or the perception that such issuances or sales might occur could materially adversely affect the market price of the shares of our common stock. Because our decision to issue securities in the future, including in connection with any future offering, will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing, or nature of our future issuances or offerings. Accordingly, our stockholders bear the risk that our future issuances and/or offerings will reduce the market price of our common stock and dilute their stock holdings in us.

We have established preferred stock which can be designated by the Board of Directors without shareholder approval.

We have 100,000 shares of preferred stock authorized, which includes 50,000 shares of Series A Convertible Preferred Stock (none of which are outstanding) and 50,000 shares of Series P preferred stock (none of which are outstanding). Shares of preferred stock may be designated and issued by our Board of Directors without shareholder approval with voting powers, and such preferences and relative, participating, optional, or other special rights and powers as determined by our Board of Directors, which may be greater than the shares of common stock currently outstanding. As a result, shares of preferred stock may be issued by our Board of Directors which cause the holders to have voting power over our shares or provide the holders of the preferred stock the right to convert the shares of preferred stock they hold into shares of our common stock, which may cause substantial dilution to our then common stock stockholders and/or have other rights and preferences (including, but not limited to voting rights) greater than those of our common stock stockholders. Investors should keep in mind that the Board of Directors has the authority to issue additional shares of preferred stock, which could cause substantial dilution to our existing stockholders or result in a change of control. Because our Board of Directors is entitled to designate the powers and preferences of the preferred stock without a vote of our stockholders, subject to NASDAQ rules and regulations, our stockholders will have no control over what designations and preferences our future preferred stock, if any, will have.

Our governing documents and Wyoming law includes various take-over defense provisions that could discourage some advantageous transactions .

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 has historically been and is likely to continue to be, volatile.

Our stock is traded on The NASDAQ Capital Market under the symbol "USEG". During the last 52 weeks, our common stock has traded as high as $18.57 per share and as low as $2.44 per share. We expect our common stock will continue to be subject to wide 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.

Our Common Stock may be delisted from The Nasdaq Capital Market if we cannot satisfy Nasdaq's continued listing requirements.

Among the conditions required for continued listing on The Nasdaq Capital Market, Nasdaq requires us to maintain at least $2.5 million in stockholders' equity or $500,000 in net income over the prior two years or two of the prior three years, to have a majority of independent directors, and to maintain a stock price over $1.00 per share. Our stockholders' equity may not remain above Nasdaq's $2.5 million minimum, we may not generate over $500,000 of yearly net income moving forward, we may not be able to maintain independent directors, and we may not be able to maintain a stock price over $1.00 per share. Delisting from The Nasdaq Capital Market could make trading our common stock more difficult for investors, potentially leading to declines in our share price and liquidity. Without a Nasdaq Capital Market listing, stockholders may have a difficult time getting a quote for the sale or purchase of our stock, the sale or purchase of our stock would likely be made more difficult and the trading volume and liquidity of our stock could decline. Delisting from The Nasdaq Capital Market could also result in negative publicity and could also make it more difficult for us to raise additional capital. The absence of such a listing may adversely affect the acceptance of our common stock as currency or the value accorded by other parties. Further, if we are delisted, we would also incur additional costs under state blue sky laws in connection with any sales of our securities. These requirements could severely limit the market liquidity of our common stock and the ability of our stockholders to sell our common stock in the secondary market. If our common stock is delisted by Nasdaq, our common stock may be eligible to trade on an over-the-counter quotation system, such as the OTCQB market, where an investor may find it more difficult to sell our stock or obtain accurate quotations as to the market value of our common stock. In the event our common stock is delisted from The Nasdaq Capital Market, we may not be able to list our common stock on another national securities exchange or obtain quotation on an over-the counter quotation system.

If we are delisted from The Nasdaq Capital Market, your ability to sell your shares of our common stock could also be limited by the penny stock restrictions, which could further limit the marketability of your shares.

If our common stock is delisted, it could come within the definition of "penny stock" as defined in the Exchange Act and would then be covered by Rule 15g-9 of the Exchange Act. That Rule imposes additional sales practice requirements on broker-dealers who sell securities to persons other than established customers and accredited investors. For transactions covered by Rule 15g-9, the broker-dealer must make a special suitability determination for the purchaser and receive the purchaser's written agreement to the transaction prior to the sale. Consequently, Rule 15g-9, if it were to become applicable, would affect the ability or willingness of broker-dealers to sell our securities, and accordingly would affect the ability of stockholders to sell their securities in the public market. These additional procedures could also limit our ability to raise additional capital in the future.

General Risk Factors

Because we are a small company, the requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act and the Dodd-Frank Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we must comply with the federal securities laws, rules and regulations, including certain corporate governance provisions of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act") and the Dodd-Frank Act, related rules and regulations of the SEC and NASDAQ, with which a private company is not required to comply. Complying with these laws, rules and regulations will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses, which we cannot estimate accurately at this time. Among other things, we must:

- establish and maintain a system of internal control over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules and regulations promulgated by NASDAQ;

- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- maintain various internal compliance and disclosures policies, such as those relating to disclosure controls and procedures and insider trading in our common stock;
- involve and retain to a greater degree outside counsel and accountants in the above activities;
- maintain a comprehensive internal audit function; and
- maintain an investor relations function.

In addition, being a public company subject to these rules and regulations may require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers.

Our business could be adversely affected by security threats, including cybersecurity threats.

We face various security threats, including cybersecurity threats to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing facilities, refineries, rail facilities and pipelines. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business, financial condition and results of operations. For example, unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruptions, or other disruptions to our operations.

Our implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for our information, systems, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to our business and operations, as well as data corruption, reputational damage, communication interruptions or other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position and results of operations.

The threat and impact of terrorist attacks, cyber-attacks or similar hostilities may adversely impact our operations.

We cannot assess the extent of either the threat or the potential impact of future terrorist attacks on the energy industry in general, and on us in particular, either in the short-term or in the long-term. Uncertainty surrounding such hostilities may affect our operations in unpredictable ways, including the possibility that infrastructure facilities, including pipelines and gathering systems, production facilities, processing plants and refineries, could be targets of, or indirect casualties of, an act of terror, a cyber-attack or electronic security breach, or an act of war.

We may have difficulty managing growth in our business, which could have a material adverse effect on our business, financial condition and results of operations and our ability to execute our business plan in a timely fashion.

Because of our small size, growth in accordance with our business plans, if achieved, will place a significant strain on our financial, technical, operational and management resources. As we expand our activities, including our planned increase in oil exploration, development and production, and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the inability to recruit and retain experienced managers, geoscientists, petroleum engineers and landmen could have a material adverse effect on our business, financial condition and results of operations and our ability to execute our business plan in a timely fashion.

Failure to adequately protect critical data and technology systems could materially affect our operations.

Information technology solution failures, network disruptions and breaches of data security could disrupt our operations by causing delays or cancellation of customer orders, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. There can be no assurance that a system failure or data security breach will not have a material adverse effect on our financial condition, results of operations or cash flows.

If we complete acquisitions or enter into business combinations in the future, they may disrupt or have a negative impact on our business.

If we complete acquisitions or enter into business combinations in the future, funding permitting, we could have difficulty integrating the acquired companies' assets, personnel and operations with our own. Additionally, acquisitions, mergers or business combinations we may enter into in the future could result in a change of control of the Company, and a change in the board of directors or officers of the Company. In addition, the key personnel of the acquired business may not be willing to work for us. We cannot predict the effect expansion may have on our core business. Regardless of whether we are successful in making an acquisition or completing a business combination, the negotiations could disrupt our ongoing business, distract our management and employees and increase our expenses. In addition to the risks described above, acquisitions and business combinations are accompanied by a number of inherent risks, including, without limitation, the following:

- the difficulty of integrating acquired companies, concepts and operations;
- the potential disruption of the ongoing businesses and distraction of our management and the management of acquired companies;
- change in our business focus and/or management;
- difficulties in maintaining uniform standards, controls, procedures and policies;
- the potential impairment of relationships with employees and partners as a result of any integration of new management personnel;
- the potential inability to manage an increased number of locations and employees;
- our ability to successfully manage the companies and/or concepts acquired;
- the failure to realize efficiencies, synergies and cost savings; or
- the effect of any government regulations which relate to the business acquired.

Our business could be severely impaired if and to the extent that we are unable to succeed in addressing any of these risks or other problems encountered in connection with an acquisition or business combination, many of which cannot be presently identified. These risks and problems could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations.

Any acquisition or business combination transaction we enter into in the future could cause substantial dilution to existing stockholders, result in one party having majority or significant control over the Company or result in a change in business focus of the Company.

We do not intend to pay dividends on our common stock for the foreseeable future.

We have never paid cash dividends on our capital stock and do not anticipate paying any cash dividends on our common stock for the foreseeable future. Investors should not rely on an investment in us if they require income generated from dividends paid on our capital stock. Because we do not intend to pay dividends on our common stock, any income derived from our common stock would only come from a rise in the market price of our common stock, which is uncertain and unpredictable.

If persons engage in short sales of our common stock, including sales of shares to be issued upon exercise of our outstanding warrants, the price of our common stock may decline.

Selling short is a technique used by a stockholder to take advantage of an anticipated decline in the price of a security. In addition, holders of options and warrants will sometimes sell short knowing they can, in effect, cover through the exercise of an option or warrant, thus locking in a profit. A significant number of short sales or a large volume of other sales within a relatively short period of time can create downward pressure on the market price of a security. Further sales of common stock issued upon exercise of our outstanding warrants could cause even greater declines in the price of our common stock due to the number of additional shares available in the market upon such exercise, which could encourage short sales that could further undermine the value of our common stock. Stockholders could, therefore, experience a decline in the values of their investment as a result of short sales of our common stock.

Stockholders may be diluted significantly through our efforts to obtain financing and satisfy obligations through the issuance of securities.

Wherever possible, our Board of Directors will attempt to use non-cash consideration to satisfy obligations. In many instances, we believe that the non-cash consideration will consist of shares of our common stock, preferred stock, or warrants to purchase shares of our common stock. Our Board of Directors has authority, without action or vote of the stockholders, subject to the requirements of The NASDAQ Capital Market (which generally require shareholder approval for any transactions which would result in the issuance of more than 20% of our then outstanding shares of common stock or voting rights representing over 20% of our then outstanding shares of stock, subject to certain exceptions, including sales in a public offering and/or sales which are undertaken at or above the lower of the closing price immediately preceding the signing of the binding agreement or the average closing price for the five trading days preceding the signing of the binding agreement), to issue all or part of the authorized but unissued shares of common stock, preferred stock or warrants to purchase such shares of common stock. In addition, we may attempt to raise capital by selling shares of our common stock, possibly at a discount to market in the future. These actions will result in dilution of the ownership interests of existing stockholders and may further dilute common stock book value, and that dilution may be material. Such issuances may also serve to enhance existing management's ability to maintain control of us, because the shares may be issued to parties or entities committed to supporting existing management.

Future litigation or governmental proceedings could result in material adverse consequences, including judgments or settlements.

From time to time, we are involved in lawsuits, regulatory inquiries and may be involved in governmental and other legal proceedings arising out of the ordinary course of our business. Many of these matters raise difficult and complicated factual and legal issues and are subject to uncertainties and complexities. The timing of the final resolutions to these types of matters is often uncertain. Additionally, the possible outcomes or resolutions to these matters could include adverse judgments or settlements, either of which could require substantial payments, adversely affecting our results of operations and liquidity.

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, 2020, 2019 and 2018 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 2020	2019	2018
Oil (per Bbl)	$ 39.57	$ 55.69	$ 65.56
Gas (per Mcfe)	$ 1.99	$ 2.58	$ 3.10

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, 2020 (1)			2019 (1)			2018 (1)		
	Oil (Bbl)	Natural Gas (Mcf)	Total (BOE)	Oil (Bbl)	Natural Gas (Mcf)	Total (BOE)	Oil (Bbl)	Natural Gas (Mcf)	Total (BOE)
Proved developed	870,877	1,676,948	1,150,368	807,510	1,129,260	995,720	751,260	738,000	874,260
Proved non-producing	104,868	-	104,868	-	-	-	-	-	-
Proved undeveloped	-	-	-	-	-	-	-	-	-
Total proved reserves	975,745	1,676,948	1,255,236	807,510	1,129,260	995,720	751,260	738,000	874,260

(1) Our reserve estimates as of December 31, 2020 and 2019 are based on reserve reports prepared by Don Jacks, PE. Mr. Jacks has been a licensed independent petroleum engineer in the State of Texas since 1992. Our reserve estimates as of December 31, 2018 are based on a reserve report 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, 2020, our proved reserves totaled 1,255,236 BOE, of which 89% were classified as proved developed and 11% were classified as proved non-producing. On a BOE basis, approximately 81% of the total proved reserves are derived from 975,745 Bbls of oil and 19% is derived from 1,676,948 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, 2020, 2019 and 2018, we did not have any and did not book any proved undeveloped ("PUD") reserves due to the lack of an approved development plan for development of PUD reserves and uncertainty regarding the availability of capital that would be required to develop any 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, 2020, 2019 and 2018.

	2020	2019	2018
Production Volume			
Oil (Bbls)	60,469	110,090	75,003
Natural gas (Mcfe)	116,082	209,518	286,692
BOE	79,816	145,010	122,785
Daily Average Production Volume			
Oil (Bbls per day)	165	302	205
Natural gas (Mcfe per day)	317	574	785
BOE per day	218	397	336
Net prices realized			
Oil per Bbl	$ 35.18	$ 55.85	$ 61.45
Natural gas per Mcfe	1.75	2.03	3.24
Oil and natural gas per BOE	29.19	45.33	45.11
Operating Expenses per BOE			
Lease operating expenses and production taxes	$ 21.34	$ 15.70	$ 18.65
Depletion, depreciation and amortization	5.09	4.78	3.20

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 under "Financial Statements and Supplemental Data".

The following table provides a regional summary of our production for the years ended December 31, 2020, 2019 and 2018

	2020			2019			2018		
	Oil (Bbl)	Natural Gas (Mcfe)	Total (BOE)	Oil (Bbl)	Natural Gas (Mcfe)	Total (BOE)	Oil (Bbl)	Natural Gas (Mcfe)	Total (BOE)
North Dakota	38,021	65,059	48,864	47,170	82,620	60,940	48,884	91,546	64,142
South Texas	18,687	30,080	23,700	62,920	126,898	84,070	26,119	88,260	40,829
West Texas (1)	2,472	12,766	4,600	-	-	-	-	-	-
Gulf Coast (2)	991	-	991	-	-	-	-	106,886	17,814
Other	298	8,177	1,661						
Total	60,649	116,082	79,816	110,090	209,518	145,010	75,003	286,692	122,785

(1) Includes properties in West Texas and Southeastern New Mexico acquired from FieldPoint Petroleum on September 25, 2020.
(2) Production in 2020 includes production from Liberty County, Texas properties acquired in December 2020 and production in Louisiana in 2018.

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, 2020, 2019 and 2018.

	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	-	-	-	-	-	-
Non-productive	-	-	-	-	-	-
Sub-total	-	-	-	-	-	-
Exploratory wells:						
Productive	-	-	4	0.16	1	0.30
Non-productive	-	-	-	-	-	-
Sub-total	-	-	4	0.16	1	0.30
Total	-	-	4	0.16	1	0.30

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* in this annual report on Form 10-K.

Present Activities. From January 1, 2021 through March 19, 2021, we have not participated in any drilling activities, nor are we in the process of participating in any drilling activities; however, we are currently in the process of returning idle wells we acquired during 2020 back to production.

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, 2020.

	Gross Producing Wells			Net Producing Wells			Average Working Interest		
	Oil	Gas	Total	Oil	Gas	Total	Oil	Gas	Total
North Dakota	89	-	89	8.0	-	8.0	8.94%	-%	8.94%
South Texas	22	-	22	4.9	-	4.9	22.07%	-%	22.07%
Gulf Coast	12		12	12.0		12.0	100.00%	-%	100.00%
New Mexico	7		7	2.7		2.7	39.14%	-%	39.14%
Other	4		4	3.1		3.1	78.05%	-%	78.05%
Total	134	-	134	30.7	-	30.7	22.89%	-%	22.89%

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, 2020.

	Developed		Undeveloped		Total	
Area	Gross	Net	Gross	Net	Gross	Net
North Dakota	73,433	2,355	-	-	73,433	2,355
South Texas	8,809	1,769	4,065	449	12,874	2,218
Gulf Coast	2,504	969	-	-	2,504	969
New Mexico	1,325	522	-	-	1,325	522
Total	86,071	5,615	4,065	449	90,136	6,064

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, 2020, all of our acreage in North Dakota, South Texas, Gulf Coast and New Mexico is held by production.

Real Estate

We are in the process of selling a 30,400 square-foot office building and 14- acre tract we own in Riverton, Wyoming. The office building once served as our corporate headquarters, but is currently rented to non-affiliates and government agencies. In addition, we own three city lots covering 13.84 acres adjacent to our office building, which we expect to sell in 2021. 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.

Office Space

We have entered into operating leases for office space in Houston and Denver. The Houston lease expires March 31, 2023 and the Denver lease, which we have subleased until its expiration, expires January 31, 2023.

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, 2020.

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.

From time to time, we may become party to litigation or other legal proceedings that we consider to be a part of the ordinary course of our business.

Such current litigation or other legal proceedings are described in, and incorporated by reference in, this “Item 3. Legal Proceedings” of this Annual Report on Form 10-K from, “Item 8. Financial Statements and Supplementary Data” in the Notes to Consolidated Financial Statements in “Note 9. Commitments, Contingencies, and Related Party Transactions”, under the heading “Litigation”. The Company believes that the resolution of currently pending matters will not individually or in the aggregate have a material adverse effect on our financial condition or results of operations. However, assessment of the current litigation or other legal claims could change in light of the discovery of facts not presently known to the Company or by judges, juries or other finders of fact, which are not in accord with management’s evaluation of the possible liability or outcome of such litigation or claims.

Additionally, the outcome of litigation is inherently uncertain. If one or more legal matters were resolved against the Company in a reporting period for amounts in excess of management's expectations, the Company's financial condition and operating results for that reporting period could be materially adversely affected.

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".

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 22, 2021, we had 4,676,301 shares of common stock issued and outstanding.

Dividends

We did not declare or pay any cash dividends on common stock during fiscal years 2020 and 2019 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.

Recent Sales of Unregistered Securities

There were no sales of unregistered securities during the three months ended December 31, 2020 and from the period from January 1, 2020 to the filing date of this report, which have not previously been included in a Quarterly Report on Form 10-Q or in a Current Report on Form 8-K.

Issuer Purchases of Equity Securities

During the year ended December 31, 2020, the Company did not repurchase any shares of its common stock. On December 31, 2020, we redeemed all 50,000 shares of Series A preferred stock by paying $2.0 million in cash and issuing 328,000 shares of our common stock to the holders of the Series A preferred 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 and "Risk Factors", above. 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 February 11, 2021, we sold 1,131,500 shares of our common stock in an underwritten offering at a public offering price of $5.10 per share (the "Offering") . The Offering closed on February 17, 2021. The net proceeds to us from the Offering, after deducting the underwriting discounts and commissions and Offering expenses, were $5.3 million. We intend to use the net proceeds from this offering for general corporate purposes, capital expenditures, working capital, and potential acquisitions of oil and gas properties.

On March 4, 2021 we entered into a Debt Conversion Agreement with APEG II. Pursuant to the Debt Conversion Agreement, APEG II converted a total of approximately $413,000, representing the principal of the Secured Promissory Note of $375,000 and accrued interest of approximately $38,000 into 97,962 unregistered shares of our common stock. The number of shares was based on a conversion price of $4.21 per share, a 9.9% discount to the ten-day volume weighted average price of our common stock for the ten days immediately preceding the signing of the Debt Conversion Agreement (the "VWAP Discount Price").

Also, on March 4, 2021, APEG II entered into a Subscription Agreement with us, whereby APEG II subscribed to purchase 90,846 unregistered shares of our common stock for an aggregate of approximately $383,000 based on the VWAP Discount Price. The $383,000 subscription price was paid by way of forgiveness by APEG II of the same amount of funds owed by us for reimbursement of APEG II's legal costs in connection with certain shareholder derivative actions brought by APEG against us and our former Chief Executive Officer in Colorado and Texas, which were dismissed in May 2020 and August, respectively.

On March 9, 2021, we entered into a commodity derivative contract to hedge the price of 100 barrels of crude oil per day from March 1 to December 31, 2021at

$61.90 based on the calendar month average of WTI Crude Oil.

Impacts of COVID-19 Pandemic and Effect on Economic Environment

In early March 2020, there was a global outbreak of COVID-19 that has resulted in a drastic decline in global demand of certain mineral and energy products including crude oil. As a result of the lower demand caused by the COVID-19 pandemic and the oversupply of crude oil, spot and future prices of crude oil fell to historic lows during the second quarter of 2020 and only recently recovered to pre-COVID-19 levels. Operators in North Dakota's Williston Basin responded by significantly decreasing drilling and completion activity and shutting in or curtailing production from a significant number of producing wells. Operators' decisions on these matters are changing rapidly and it is difficult to predict the future effects on the Company's business. 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.

Additionally, the outbreak of COVID-19 and decreases in commodity prices resulting from oversupply, government-imposed travel restrictions, and other constraints on economic activity have caused a significant decrease in the demand for oil and has created disruptions and volatility in the global marketplace for oil and gas beginning in the first quarter of 2020, which negatively affected our results of operations and cash flows. These conditions persisted throughout 2020 and continue to negatively affect our results of operations and cash flows. While demand and commodity prices have shown signs of recovery, they are not back to pre-pandemic levels, and financial results may continue to be depressed in future quarters. The extent to which the COVID-19 pandemic impacts our business going forward will depend on numerous evolving factors we cannot reliably predict, including the duration and scope of the pandemic; governmental, business, and individuals' actions in response to the pandemic; and the impact on economic activity including the possibility of recession or financial market instability. These factors may adversely impact the supply and demand for oil and gas and our ability to produce and transport oil and gas and perform operations at and on our properties. This uncertainty also affects management's accounting estimates and assumptions, which could result in greater variability in a variety of areas that depend on these estimates and assumptions, including investments, receivables, and forward-looking guidance.

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 under "Financial Statements and Supplementary Data". 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.

Joint Interest Operations. The majority of our properties are operated by other companies. 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. Revenue statements and 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.

Acquisitions. The Company accounts for acquisitions as business combinations if the acquired assets meet the definition of a business. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar assets, the acquisition is not considered a business and is accounted for as an asset acquisition. This determination of whether the gross assets acquired are concentrated in a group of similar assets is based on whether the risks associated with managing and creating outputs from the assets are similar.

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. *Note 4- Revenue Recognition* to our consolidated financial statements included in Item 8 of this report on Form 10-K under "Financial Statements and Supplementary Data"

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. During 2020, 50,000 of the warrants were exercised, leaving 50,000 warrants outstanding at December 31, 2020. 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. On December 31, 2020, we redeemed all outstanding shares of our Series A Convertible Preferred Stock, as discussed above. In previous periods, we have excluded our Series A Convertible Preferred Stock from stockholders' equity due to a redemption feature whereby the holders of the preferred stock had the option to redeem their shares in the event of a change of control, which is outside of our control. See *Note 10- Preferred Stock* to our consolidated financial statements included in Item 8 of this report on Form 10-K under "Financial Statements and Supplementary Data" 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 under "Financial Statements and Supplementary Data" 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, 2020 and 2019

During the year ended December 31, 2020, we recorded a net loss of $6.4 million as compared to a net loss of $0.6 million for the year ended December 31, 2019. In the following sections we discuss our revenue, operating expenses, and non-operating income for the year ended December 31, 2020, compared to the year ended December 31, 2019.

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, 2020 and 2019 (dollars in thousands, except average sales prices):

			Change	
	2020	2019	Amount	Percent
Revenue:				
Oil	$ 2,127	$ 6,149	$ (4,022)	-65%
Gas	203	424	(221)	-52%
Total	$ 2,330	6,573	$ (4,243)	-65%
Production quantities:				
Oil (Bbls)	60,469	110,090	(49,621)	-45%
Gas (Mcfe)	116,082	209,518	(93,436)	-45%
BOE	79,816	145,010	(65,194)	-45%
Average sales prices:				
Oil (Bbls)	$ 35.18	$ 55.85	$ (20.67)	-37%
Gas (Mcfe)	1.75	2.03	(0.28)	-14%
BOE	29.19	45.33	(16.14)	-36%

The decrease in our oil sales of $4.0 million for the year ended December 31, 2020, compared to the prior year's period resulted from a 45% decrease in production quantities and a 37% decrease in the average sales price received during 2020, compared to 2019. The decline in oil prices is primarily due to reduced demand on a global basis beginning in mid-March 2020, as a result of the COVID-19 pandemic. In addition, our oil price differential widened for our North Dakota properties where the differential from WTI increased to $6.60 per barrel in 2020, compared to $5.06 per barrel in 2019. The decrease in oil production quantities is the result of operators shutting in production in our North Dakota properties beginning in April 2020 as a response to low oil prices, and the production declines from our South Texas wells, which were drilled in late 2018 and early 2019.

For the year ended December 31, 2020, we produced 79,816 BOE, or an average of 218 BOE per day, as compared to 145,010 BOE or 397 BOE per day in 2019. Production from our properties in South Texas decreased by 60,369 BOE during 2020, a 72% decrease compared to 2019. This decrease was attributable to steep production declines related to wells drilled in our South Texas properties in late 2018 and early 2019. In addition, production from our Williston Basin properties decreased by 12,076 BOE during 2020, which is a 20% reduction compared to 2019. This decrease is primarily due to operators in North Dakota shutting-in production due to low oil prices in the second fiscal quarter of 2020. These declines were partially offset by production from properties acquired during 2020 of 7,252 BOE.

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, 2020 and 2019 (in thousands):

							Change	
		2020		**2019**		**Amount**		**Percent**
Lease operating expenses	$	1,535	$	1,848	$	(313)		-17%
Production taxes		168		429		(261)		-60%
Total	$	1,703	$	2,277	$	(574)		-25%

For the year ended December 31, 2020, lease operating expense decreased by $313 thousand or 17% due to cost cutting measures enacted due to low commodity prices and reduced field activity. Production taxes decreased by $261 thousand or 60% compared to 2019. The decrease in production taxes is the result of decreased revenue from oil and natural gas revenue of 65%.

Depreciation, Depletion and Amortization. Our DD&A rate for the year ended December 31, 2020 was $5.09 per BOE, compared to $4.78 per BOE for year ended December 31, 2019. During 2020, our depletion rate was impacted by a reclassification of $2.1 million of our unevaluated properties and ceiling test write downs of $2.9 million. 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. For the year ended December 31, 2020, we recorded an impairment of $2.9 million due to the net capitalized cost of our oil and natural gas properties exceeding the full cost ceiling limitation. For the year ended December 31, 2019, there was no such full cost ceiling limitation.

General and Administrative Expenses. Presented below is a comparison of our general and administrative expenses for the years ended December 31, 2020 and 2019 (in thousands):

							Change	
		2020		**2019**		**Amount**		**Percent**
Compensation and benefits, including directors	$	1,141	$	1,187	$	(46)		-4%
Professional fees, insurance and other		1,506		3,178		(1,672)		-53%
Bad debt expense		-		28		(28)		-%
Total	$	2,647	$	4,393	$	(1,746)		-40%

General and administrative expenses decreased by $1,746 thousand for the year ended December 31, 2020 as compared to the year ended December 31, 2019 primarily due to a reduction in professional fees of $1,672 thousand. The decrease in professional fees was primarily attributable to a reduction in legal fees of $1,431 thousand of which $1,216 thousand was directly related to the APEG II litigation and the forensic accounting review. See *Litigation—APEG II Litigation* and *–Litigation with Former Chief Executive Officer* in *Note 9—Commitments, Contingencies and Related-Party Transactions* in the Notes to the Financial Statements included in Item 8 of this annual report on Form 10-K under "Financial Statements and Supplementary Data". Compensation and benefits decreased $46 thousand due to a reduction in salary expense of $198 thousand due to lower headcount and a reduction in accrued bonuses of $92 thousand. These reductions were partially offset by a $170 thousand increase in the amortization of stock-based compensation awards granted to our Chief Executive Officer and directors in January 2020 and an increase in director compensation of $75 thousand, due to an increase in the number of directors serving on the board of directors.

Non-Operating Income (Expense). Presented below is a comparison of our non-operating income (expense) for the years ended December 31, 2020 and 2019 (in thousands):

							Change	
		2020		**2019**		**Amount**		**Percent**
Loss on real estate assets held for sale		(1,054)		-		(1,054)		-100%
Loss on marketable equity securities		(81)		(229)		148		65%
Warrant revaluation (loss) gain		(23)		352		(375)		-107%
Rental property loss		(27)		(72)		45		63%
Other income		88		200		(112)		56%
Interest expense, net		(14)		(11)		(3)		-27%
Total other (expense) income	$	(1,111)	$	240	$	(1,351)		-563%

During the year ended December 31, 2020 we reclassified our Riverton, Wyoming office building and land to real estate held for sale. Concurrent with the reclassification we recognized a $651 thousand loss to adjust the carrying amount of the land and building to its estimated fair value of $725 thousand and an additional $403 thousand loss to adjust the carrying amount of three land parcels adjacent to our building to their estimated fair value of $250 thousand. See Note 3—Real Estate Held for Sale in the notes to the consolidated financial statements included in this report.

During the year ended December 31, 2020 we recognized an unrealized loss on marketable equity securities of $81 thousand as compared to an unrealized loss of $229 thousand for the comparable period of 2019. The unrealized loss represents the decline in value of our investment in Anfield Energy Inc. In July 2020, we sold 1,210,455 shares, representing one-third of our total investment for proceeds of $45 thousand. We expect to sell the remaining shares in the second quarter of 2021.

During the year ended December 31, 2020, we recognized a warrant revaluation loss of $23 thousand as compared to a gain of $352 thousand during the year ended December 31, 2019. The current year loss was attributable to an increase in the warrant liability, primarily as a result of the increase in the value of our common stock, which was partially offset by the exercise of 50,000 warrants during the period.

In 2018, due to uncertainty of collection, we wrote off a receivable of $374 thousand related to a refundable deposit for a transaction that was not completed. During the year ended December 31, 2020, we recovered $75 thousand of the receivable. During the year ended December 31, 2019 we recovered $200 thousand related to the recovery of the same receivable. The total amounts of the receivable collected through December 31, 2020 is $275 thousand. The recovery of the deposit is included in other income in the table above.

Interest, net increased by $3 thousand during the year ended December 31, 2020 compared to the comparable period in 2019. Interest in the current year is attributable to interest accrued on the $375 thousand secured note payable with APEG II, which we borrowed in September 2020. Interest in the prior year represents interest on our credit facility, which was repaid in full on March 1, 2019.

Liquidity and Capital Resources

Based on the current commodity price environment, we believe we have sufficient liquidity and capital resources to execute our business plan while continuing to meet our current financial obligations in a challenging commodity price environment.

We have no control over the market prices for oil, and natural gas, although we may be able to influence the amount of our realized revenues from our oil, and natural gas sales through the use of derivative contracts. In March 2021, we entered into a crude oil swap contract to fix the price of 100 barrels of our crude production oil per day from March 1 to December 31, 2021 at $61.90 per barrel. 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. Commodity derivative contracts may limit the prices we receive for our oil and natural gas sales if prices rise substantially over the price established by the commodity derivative contract.

The following table sets forth certain measures about our liquidity as of December 31, 2020 and 2019, in thousands:

	2020	2019	Change
Cash and equivalents	$ 2,854	$ 1,532	$ 1,322
Working capital surplus [(1)]	2,499	1,470	1,029
Total assets	12,363	13,467	(1,104)
Outstanding debt	375	-	375
Total shareholders' equity	8,567	9,210	(643)
Select Ratios:			
Current ratio [(2)]	2.17 to 1.00	2.20 to 1.00	
Debt-to-equity ratio [(3)]	0.04 to 1.00	N/A	

(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, 2020, we had a working capital surplus of $2.5 million compared to a working capital surplus of $1.5 million as of December 31, 2019, an increase of $1.0 million. This increase was primarily attributable to $4.5 million in proceeds received from offerings of our common stock during the period less $2.0 million paid for the redemption of our Series A preferred stock and cash of approximately $1.0 million paid for acquisitions and development of our oil and natural gas properties.

As of December 31, 2020, we had cash and cash equivalents of $2.9 million and accounts payable and accrued liabilities of $1.5 million. As of March 22, 2021, we had cash and cash equivalents of $7.3 million and accounts payable and accrued liabilities of approximately $0.9 million.

We own a 14-acre tract in Riverton, Wyoming with a two-story, 30,400 square foot office building and an additional 13-acre parcel of land adjacent to the building. The building served as our corporate headquarters until 2015 and is currently being leased to government agencies and other non-affiliated companies. During 2020, we made the decision to sell the land and building and began a process to determine the price at which we would list the property for sale. The process included obtaining an appraisal, analyzing operating statements for the building, reviewing capitalization rates and consulting a large national commercial real estate company. We determined the realizable value of the real estate assets was in the range of $950 thousand to $1.2 million. A special committee of the board of directors was formed to evaluate the sales process and during 2020, we entered into an agreement with a large national commercial broker and a local broker in Riverton, Wyoming to sell our real estate assets.

In July 2020, we sold 1,210,455 shares of our investment in Anfield Energy Inc. and received proceeds of approximately $45 thousand. The sale represented one-third of our total investment in Anfield. We intend to dispose of the remaining shares during the second fiscal quarter of 2021.

In the fourth fiscal quarter of 2020, we closed on a registered direct offering of 315,810 shares of our common stock and underwritten offering of an additional 1,150,000 shares of our common stock. The net proceeds from the offerings were approximately $4.5 million. In addition, in February 2021, we closed an underwritten offering of 1,131,600 shares of our common stock and received net proceeds of approximately $5.3 million.

If we have needs for financing in 2021, alternatives that we will consider would potentially include entering into a reserve-based credit facility, selling all or a partial interest in certain of our non-operated oil and natural gas assets, selling our marketable equity securities, issuing additional 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, 2020 and 2019 (in thousands):

	2020	2019	Change
Net cash provided by (used in):			
Operating activities	$ (717)	$ 638	$ (1,355)
Investing activities	(1,109)	(281)	(828)
Financing activities	3,148	(1,165)	4,313

Operating Activities. Cash used in operating activities for the year ended December 31, 2020, was $0.7 million as compared to cash provided by operating activities of $0.6 million for 2019, an increase of $1.3 million. This increase was primarily related to the decrease in oil revenues as a result of a reduction in oil prices combined with production declines, primarily in our South Texas properties.

Investing Activities. Cash used in investing activities for the year ended December 31, 2020, was $1.1 million compared to cash used in investing activities of $0.3 million for 2019, an increase of $0.8 million. The increase in cash used in investing activities was primarily attributable the acquisitions we completed during the year and well work that we performed to bring some of the idle wells acquired back to production.

Financing Activities. Cash provided by financing activities for the year ended December 31, 2020, was $3.1 million as compared to cash used in financing activities of $1.2 million for 2019, an increase of $4.3 million. The increase was due to net proceeds of $4.5 million from the issuance of common stock, $0.6 million in proceeds from the exercise of stock purchase warrants, and $0.4 million from the related party note payable. These increases were partially offset by a cash payment of $2.0 million for the redemption of our Series A preferred stock and $0.2 million in payments on our note payable to finance insurance premiums. In 2019, cash used in financing activities was primarily due to $0.9 million paid on credit facility and $0.2 million in payments on the note payable to finance insurance premiums.

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, 2020.

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 Chief 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, 2020 our Chief Executive Officer and Chief 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 Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

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, 2020. 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, 2020, 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, 2020:

- We had inadequate segregation of duties as a result of limited accounting staff and resources, which may impact our ability to prevent or detect material errors in our consolidated financial statements.
- We had inadequate segregation of duties related to logical access to our accounting systems, which may affect our ability to prevent or detect material errors in the recorded transactions.

Changes in Internal Control Over Financial Reporting.

There have been no changes to our system of internal control over financial reporting during the year and fiscal quarter ended December 31, 2020 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.

Limitations on the Effectiveness of Controls

The Company's disclosure controls and procedures are designed to provide the Company's Chief Executive Officer and Chief Financial Officer with reasonable assurances that the Company's disclosure controls and procedures will achieve their objectives. However, the Company's management does not expect that the Company's disclosure controls and procedures or the Company's internal control over financial reporting can or will prevent all human error. A control system, no matter how well designed and implemented, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Furthermore, the design of a control system must reflect the fact that there are internal resource constraints, and the benefit of controls must be weighed relative to their corresponding costs. Because of the limitations in all control systems, no evaluation of controls can provide complete assurance that all control issues and instances of error, if any, within the Company are detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur due to human error or mistake. Additionally, controls, no matter how well designed, could be circumvented by the individual acts of specific persons within the organization. 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 its stated objectives under all potential future conditions.

Attestation Report of the Registered Public Accounting Firm

This report does not include an attestation report of our registered public accounting firm regarding our internal controls over financial reporting. Under SEC rules, such attestation is not required for smaller reporting companies such as the Company.

Item 9B – Other Information.

None.

PART III

Information required by Items 10, 11, 12, 13 and 14 of Part III is omitted from this Annual Report and will be filed in a definitive proxy statement or by an amendment to this Annual Report not later than 120 days after the end of the fiscal year covered by this Annual Report.

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this Item will be set forth under the headings "Requirements and Deadlines for Shareholders to Submit Proposals", "Election of Directors", "Executive Officers", "Corporate Governance", "Code of Conduct", "Committees of the Board", and "Delinquent Section 16(a) Reports" (to the extent applicable and warranted) in the Company's 2021 Proxy Statement to be filed with the SEC within 120 days after December 31, 2020 in connection with the solicitation of proxies for the Company's 2021 annual meeting of shareholders and is incorporated herein by reference.

Item 11. Executive Compensation.

The information required by this Item will be set forth under the headings “Executive and Director Compensation”, “Executive Compensation”, “Directors Compensation”, “Outstanding Equity Awards at Fiscal Year-End”, “Compensation Committee Interlocks and Insider Participation” and “Compensation Committee Report” (to the extent required), in the Company’s 2021 Proxy Statement to be filed with the SEC within 120 days after December 31, 2020 and is incorporated herein by reference.

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

The information required by this Item will be set forth under the heading “Principal Holders of Voting Securities and Ownership by Officers and Directors” and “Equity Compensation Plan Information” in the Company’s 2021 Proxy Statement to be filed with the SEC within 120 days after December 31, 2020 and is incorporated herein by reference.

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

The information required by this Item will be set forth under the headings “Certain Relationships and Related Transactions” and “Director Independence” in the Company’s 2021 Proxy Statement to be filed with the SEC within 120 days after December 31, 2020 and is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services.

The information required by this Item will be set forth under the heading “Ratification of Appointment of Independent Auditors”-”Principal Accounting Fees and Services” in the Company’s 2021 Proxy Statement to be filed with the SEC within 120 days after December 31, 2020 and is incorporated herein by reference.

Report of Independent Registered Public Accounting Firm

To the Shareholders and 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 Subsidiaries (the “Company”) as of December 31, 2020 and 2019, 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, 2020, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the two year period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

The Company’s management is responsible for these financial statements. Our responsibility is to express an opinion on the Company’s 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 audit to obtain reasonable assurance about whether the 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 financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the 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 financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Impact of Proved Oil and Natural Gas Reserves on Oil and Natural Gas Properties - Refer to Notes 1 and 6 of the financial statements.

Critical Audit Matter Description

The Company’s net oil and natural gas properties balance was $7.4 million as of December 31, 2020, depreciation, depletion, and amortization expense was $0.4 million and impairment of oil and natural gas properties was $2.9 million for the year ended December 31, 2020. The Company follows the full cost method of accounting for its oil and natural gas properties. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center are subject to depreciation, depletion, and amortization using the equivalent unit-of-production method, based on total proved oil and natural gas reserves. 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, as defined in note 1. As disclosed by management, the proved oil and natural gas reserves used in the calculation of depreciation, depletion, amortization and the cost center ceiling test is a significant estimate and are inherently imprecise and subject to inherent uncertainties, including the future prices of oil and natural gas, which are expected to change as future information becomes available and such changes could be material. Management utilizes a specialist to estimate proved oil and natural gas reserves.

We identified the assessment of the impact of proved oil and natural gas reserves on depreciation, depletion, and amortization expense and the cost center ceiling test related to oil and natural gas properties as a critical audit matter. There are significant judgements by management, including the use and oversight of management's specialist when developing the estimate of proved oil and natural gas reserves. In turn, performing audit procedures and evaluating audit evidence obtained related to these significant estimates and judgements required a high degree of judgement and effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures performed to address this critical audit matter included the following, among others:

- We obtained an understanding of management's process to develop estimates of proved oil and natural gas reserves and evaluated the key control used by management to develop these estimates.
- We tested the completeness and accuracy of the underlying information used by management in determining the estimate of proved oil and natural gas reserves by assessing the methodology used in estimating proved oil and natural gas reserves by management and its specialist.
- We evaluated the significant assumptions utilized by management in determining its estimate including commodity prices and price differentials, forecasted production, and estimated future operating costs. We also compared these assumptions to historical and actual results as well as publicly available prices and relevant market differentials.
- We evaluated the work of management's specialist by analyzing their objectivity, experience, and qualifications.
- We analyzed the depreciation, depletion, and amortization calculation for compliance with regulatory standards and recalculated it.
- We analyzed the cost center ceiling test for compliance with regulatory standards and recalculated it.

Unevaluated Properties - Refer to Notes 1 and 6 of the financial statements.

Critical Audit Matter Description

The Company's unevaluated properties balance was $1.6 million as of December 31, 2020 and during the year ended December 31, 2020, $2.1 million of unevaluated properties were reclassified to the depletable base of the full cost pool. The Company follows the full cost method of accounting for its oil and natural gas properties. Unevaluated properties are excluded from the depletion, depreciation and amortization calculation and the cost center ceiling until a determination about the existence of proved reserves can be completed. Unevaluated property costs are transferred to evaluated properties to the extent that management subsequently determines the properties are impaired or if proved reserves are established.

We identified the evaluation of unevaluated properties as a critical audit matter as there are significant judgements by management that impact the classification of the unevaluated property costs and potential impacts on depreciation, depletion, and amortization and the cost center ceiling when impaired unevaluated properties are transferred to evaluated properties. Performing audit procedures and evaluating audit evidence obtained related to management's estimates and judgement required a high degree of judgement and effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures performed to address this critical audit matter included the following, among others:

- We obtained an understanding of management's process of assessment of the unevaluated properties and evaluated the key control used by management in this assessment.
- We assessed the unevaluated properties' status and management's plans for the unevaluated properties for impairment considerations including lease terms and historic holding periods.

Evaluation of the Acquisition of Proved Oil and Natural Gas Properties as an Asset Acquisition – Refer to Notes 1 and 2 of the financial statements.

Critical Audit Matter Description

On September 25, 2020, the Company acquired certain oil and gas properties, as well as assumed certain liabilities from FieldPoint Petroleum Corporation pursuant to FieldPoint's Chapter 7 bankruptcy process at a purchase price of $500,000. The Company applied the applicable accounting guidance which requires the acquirer to determine if the acquisition should be accounted for as an asset acquisition or a business combination. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar assets, the acquisition is not considered a business and is accounted for as an asset acquisition. This determination of whether the gross assets acquired are concentrated in a group of similar assets is based on whether the risks associated with managing and creating outputs from the assets are similar.

We identified the evaluation of the acquisition as a critical audit matter as there are significant judgements by management in determining whether the transaction meets the definition of a business, specifically as to whether substantially all of the fair value of the gross assets acquired are concentrated in a group of similar assets based on the similarities of risks associated with managing and creating outputs from the assets. Performing audit procedures and evaluating audit evidence obtained related to management's judgement required a high degree of judgement and effort.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures performed to address this critical audit matter included the following, among others:

- We obtained an understanding of management's process to analyze the assets acquired with the related applicable accounting guidance and evaluated the key control used by management in making this determination.
- We read the acquisition agreement and evaluated management's judgements related to the determination of whether substantially all of the fair value of the gross assets acquired are concentrated in a group of similar assets by analyzing the risk characteristics of the assets acquired for similarities associated with managing and creating outputs, including operational and business risk encompassing commodity price risk, geographic location and operating environment, geological formation, resource classification, ownership interests, operating status, and stage of life of the assets acquired.

/s/ Plante & Moran PLLC

We have served as the Company's auditor since 2018.
Denver, Colorado
March 26, 2021

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
DECEMBER 31, 2020 AND 2019
(in thousands, except share and per share amounts)

		2020		2019
ASSETS				
Current assets:				
Cash and equivalents	$	2,854	$	1,532
Oil and natural gas sales receivable		514		716
Marketable equity securities		181		307
Prepaid and other current assets		184		138
Real estate assets held for sale, net of selling costs		975		-
Total current assets		4,708		2,693
Oil and natural gas properties under full cost method:				
Unevaluated properties		1,597		3,741
Evaluated properties		93,549		89,113
Less accumulated depreciation, depletion, amortization and impairment		(87,708)		(84,400)
Net oil and natural gas properties		7,438		8,454
Other assets:				
Property and equipment, net		25		2,115
Right of use asset		127		179
Other assets		65		26
Total other assets		217		2,320
Total assets	$	12,363	$	13,467
LIABILITIES AND SHAREHOLDERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities	$	1,457	$	974
Accrued compensation and benefits		312		191
Related party secured note payable		375		-
Current lease obligation		65		58
Total current liabilities		2,209		1,223
Noncurrent liabilities:				
Asset retirement obligations		1,408		819
Warrant liability		95		73
Long-term lease obligation, net of current portion		78		142
Other noncurrent liabilities		6		-
Total noncurrent liabilities		1,587		1,034
Total liabilities		3,796		2,257
Commitments and contingencies (Note 9)				
Preferred stock: Authorized 100,000 shares, 0 and 50,000 shares of Series A Convertible (par value $0.01) issued and outstanding as of December 31, 2020 and 2019, respectively; liquidation preference of $0 and $3,228 as of December 31, 2020 and 2019, respectively		-		2,000
Shareholders' equity:				
Common stock, $0.01 par value; unlimited shares authorized; 3,317,893 and 1,340,583 shares issued and outstanding as of December 31, 2020 and 2019, respectively		33		13
Additional paid-in capital		142,652		136,876
Accumulated deficit		(134,118)		(127,679)
Total shareholders' equity		8,567		9,210
Total liabilities, preferred stock and shareholders' equity	$	12,363	$	13,467

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2020 and 2019
(in thousands, except share and per share amounts)

	2020	2019
Revenue:		
Oil	$ 2,127	$ 6,149
Natural gas and liquids	203	424
Total revenue	2,330	6,573
Operating expenses:		
Oil and natural gas operations:		
Lease operating expense	1,535	1,848
Production taxes	168	429
Depreciation, depletion, accretion and amortization	407	693
Impairment of oil and natural gas properties	2,943	-
General and administrative:		
Compensation and benefits	1,141	1,187
Professional fees, insurance and other	1,506	3,178
Bad debt expense	-	28
Total operating expenses	7,700	7,363
Operating Loss	(5,370)	(790)
Other income (expense):		
Loss on real estate held for sale	(1,054)	-
Loss of marketable equity securities	(81)	(229)
Warrant revaluation (loss) gain	(23)	352
Rental and other loss	(27)	(72)
Recovery of deposit	75	200
Other income	13	-
Interest expense, net	(14)	(11)
Total other (expense) income	(1,111)	240
Loss before income taxes	**$ (6,481)**	**(550)**
Income tax benefit	42	-
Net loss	**$ (6,439)**	**$ (550)**
Preferred stock dividends	$ 20	$ (372)
Net loss applicable to common shareholders	**$ (6,419)**	**$ (922)**
Basic and diluted weighted average shares outstanding	1,627,517	1,340,583
Basic and diluted net loss per share	$ (3.94)	$ (0.69)

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2020 and 2019
(in thousands, except share amounts)

	Common Stock		Additional Paid-in	Accumulated	
	Shares	Amount	Capital	Deficit	Total
Balances, December 31, 2019	1,340,583	$ 13	$ 136,876	$ (127,679)	$ 9,210
Settlement of fractional shares in cash	(327)	-	(1)	-	(1)
Shares issued for acquisition of New Horizon Resources	59,498	1	239	-	240
Shares issued for acquisition of Liberty County properties	67,254	1	284		285
Shares issued for transaction costs in FieldPoint acquisition	7,075	-	29		29
Issuance of shares in registered direct offering, net of offering costs of $158	315,810	3	1,496		1,499
Issuance of shares in underwritten offering, net of offering costs of $482	1,150,000	11	2,957		2,968
Exercise of stock warrants	50,000	1	564		565
Adjustment of Series A Preferred Stock to redemption value (Note 10)	-	-	(1,207)		(1,207)

Issuance of shares for redemption of Series A Preferred Stock	328,000		3		1,204		-		1,207
Share-based compensation	-		-		211		-		211
Net loss	-		-		-		(6,439)		(6,439)
Balances, December 31, 2020	3,317,893	$	33	$	142,652	$	(134,118)	$	8,567
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

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2020 AND 2019
(in thousands)

		2020		2019
Cash flows from operating activities:				
Net loss	$	(6,439)	$	(550)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Depreciation, depletion, accretion, and amortization		467		828
Impairment of oil and gas properties		2,943		-
Loss on real estate assets held for sale		1,054		-
Change in fair value of warrants		23		(352)
Loss on marketable equity securities		81		229
Stock-based compensation		211		41
Right of use asset amortization		53		48
Debt issuance cost amortization		-		7
Bad debt write-off		-		28
Changes in operating assets and liabilities:				
Decrease (increase) in:				
Oil and natural gas sales receivable		214		(49)
Other current assets		153		231
Increase (decrease) in:				
Accounts payable accrued liabilities		461		100
Accrued compensation and benefits		120		129
Payments on operating lease liability		(58)		(52)
Net cash (used in) provided by operating activities		(717)		638
Cash flows from investing activities:				
Acquisition of oil and natural gas properties, net of cash acquired		(699)		(376)
Oil and gas properties capital expenditures		(475)		-
Proceeds from sale of marketable equity securities		45		-
Proceeds from sale of oil and natural gas properties		-		75
Payment received on notes receivable		20		20
Net cash used in investing activities:		(1,109)		(281)
Cash flows from financing activities:				
Issuance of common stock, net of fees		4,468		-
Proceeds from warrant exercise		565		-
Proceeds from related party secured note payable		375		-
Redemption of Series A Preferred Stock		(2,000)		-
Payments on insurance premium finance note		(198)		(228)
Payments on credit facility		(61)		(937)
Payment for fractional shares in reverse stock split		(1)		-
Net cash provided by (used in) financing activities		3,148		(1,165)
Net increase (decrease) in cash and equivalents		1,322		(808)
Cash and equivalents, beginning of year		1,532		2,340
Cash and equivalents, end of year	$	2,854	$	1,532

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

U.S. ENERGY CORP. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, Continued
FOR THE YEARS ENDED DECEMBER 31, 2020 AND 2019
(in thousands)

	2020	2019
Supplemental disclosures of cash flow information and non-cash activities:		
Cash payments for interest	$ 5	$ 11
Investing activities:		
Issuance of stock for acquisitions	554	-
Change in capital expenditure accruals	21	176
Exchange of undeveloped acreage for oil and gas properties	-	379
Asset retirement obligations assumed in acquisitions	558	-
Asset retirement obligations additions for new wells	-	130
Adoption of lease standard	-	252
Asset retirement obligations changes in assumptions	12	(14)
Financing activities:		
Shares issued in redemption of Series A preferred stock	1,207	-
Financing of insurance premiums with note payable	198	228

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

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

1. ORGANIZATION, OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Organization and Operations

U.S. Energy Corp. (collectively with its wholly owned subsidiaries, Energy One LLC and New Horizon Resources, 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 on 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; valuation of real estate assets held for sale; 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. In early March 2020, the NYMEX WTI crude oil price decreased significantly due to COVID-19 pandemic and although it has recovered recently to pre-COVID-19 levels, it remained low for most of 2020. 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.

Principles of Consolidation

The accompanying financial statements include the accounts of U.S. Energy Corp. and its wholly owned subsidiaries Energy One LLC (“Energy One”) and New Horizon Resources LLC (“New Horizon”). All inter-company balances and transactions have been eliminated in consolidation.

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, 2020, and 2019, 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	2020	2019
Zavanna, LLC	41%	31%
CML Exploration, LLC	25%	52%

Marketable Equity Securities

Marketable equity securities are reported at fair value based on end of period quoted prices. Changes in fair value are recorded in the consolidated statements of operations at the end of each reporting period. Gains or losses from sales of marketable equity securities are recorded in the consolidated statements 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.

Acquisitions

The Company accounts for acquisitions as business combinations if the acquired assets meet the definition of a business. If substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or a group of similar assets, the acquisition is not considered a business and is accounted for as an asset acquisition. This determination of whether the gross assets acquired are concentrated in a group of similar assets is based on whether the risks associated with managing and creating outputs from the assets are similar.

Property and Equipment

Land, buildings, and building improvements are classified as held for sale and are carried at the estimated realizable value, less costs to sell. 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.

Administrative assets are carried at cost. Depreciation of administrative assets is provided principally by the straight-line method over estimated useful lives as follows:

	Years
Administrative assets:	
Computers and software	3 to 10
Office furniture and equipment	5 to 20

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.

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, of which 50,000 were outstanding at December 31, 2020. 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.

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, 2020 and 2019, 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, 2020.

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 restricted stock, and prior to the redemption of such preferred stock on December 31, 2020, the Series A Convertible 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

Fair Value Measurements. In August 2018, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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. As a result of the Company's adoption of this ASU on January 1, 2020, the fair value measurement disclosures for the warrants, which are the Company's only Level 3 fair value measurement changed. The Company removed the disclosure of the processes for measuring the warrants and added quantitative information of the significant unobservable inputs used to develop the valuation of the warrants.

2. ACQUISITIONS

New Horizon Resources

On March 1, 2020, the Company acquired all the issued and outstanding equity interests of New Horizon. Its assets include acreage and operated producing properties in North Dakota (the "New Horizon Properties"). The Company accounted for the acquisition of the New Horizon Properties as a business combination. The consideration paid at closing consisted of 59,498 shares of the Company's common stock, $150,000 in cash and the assumption of certain liabilities (the "New Horizon Acquisition"). The New Horizon Acquisition gives the Company operated properties in its core area of operations. The New Horizon Properties consist of nine gross wells (five net wells), and approximately 1,300 net acres located primarily in McKenzie and Divide Counties, North Dakota, which are 100% held by production and average a 63% working interest.

	Amount
	(in thousands)
Fair value of net assets:	

Proved oil and natural gas properties	$	564
Other current assets		14
Other long-term assets		58
Total assets acquired		636
Asset retirement obligations		(163)
Current payables		(50)
Credit facility		(61)
Net assets acquired	$	362
Fair value of consideration paid for net assets:		
Cash consideration	$	150
Issuance of common stock (59,498 shares at $4.04 per share)		240
Cash acquired		(28)
Total fair value of consideration transferred	$	362

For the year ended December 31, 2020, the Company recorded revenues of approximately $101 thousand, and lease operating and workover expenses of approximately $231 thousand related to the New Horizon Properties. Assuming that the acquisition of the New Horizon properties had occurred on January 1, 2019, the Company would have recorded revenues of $132 thousand and expenses of $252 thousand for the year ended December 31, 2020, and revenues of $357 thousand and expenses of $584 thousand for the year ended December 31, 2019. These results are not necessarily indicative of the results that would have occurred had the Company completed the acquisition on the date indicated, or that will be attained in the future. Subsequent to the closing of the New Horizon Acquisition, the Company repaid the outstanding liabilities assumed at closing.

Acquisition of FieldPoint Properties

On September 25, 2020, the Company acquired certain oil and gas properties primarily located in Lea County, New Mexico and Converse County, Wyoming. The properties were acquired from FieldPoint Petroleum Corporation ("FieldPoint") pursuant to FieldPoint's Chapter 7 bankruptcy process (the "FieldPoint Properties"). The Company accounted for the acquisition of the FieldPoint Properties as an asset acquisition. The total amount paid for the FieldPoint Properties as of December 31, 2020, was $597 thousand, which includes the purchase price of $500 thousand and transaction costs of $97 thousand of which $29 thousand were paid via the issuance of 7,075 shares of the Company's common stock. The Company also recorded purchase price adjustments of $31 thousand for net revenues received, less operating expense related to periods prior to the closing of the transaction. In addition, the Company recorded asset retirement obligations of $203 thousand for the assets acquired. Substantially all of the value of the acquired FieldPoint Properties consists of mature proved developed producing reserves. Following is a summary of the amounts recorded for the assets acquired:

		Amount
		(in thousands)
Amounts incurred:		
Cash consideration	$	500
Transaction costs		97
Purchase price adjustments		(31)
Total consideration paid		566
Asset retirement obligations assumed		203
Total amount incurred	$	769

Acquisition of Liberty County Properties

On November 9, 2020, the Company entered into a Purchase and Sale Agreement (the " PSA") to acquire certain assets from Newbridge Resources LLC ("Newbridge"). The transaction closed on December 1, 2020 with an effective date of November 1, 2020. The assets include operated producing properties in Liberty County, Texas (the "Liberty County Properties"). The Liberty County Properties include 41 wells which have a 100% working interest and an average 86% net revenue interest and approximately 680 net acres located primarily in Liberty County, Texas which are 100% held by production. The Company issued 67,254 shares of its common stock, which at the closing price of $4.24 on the date of the closing of the PSA were valued at $285 thousand, in consideration for the acquisition. The Company accounted for the acquisition of the Liberty County Properties as an asset acquisition. The total amount paid as of December 31, 2020, was $326 thousand including transaction costs of $41 thousand. In addition, the Company recorded asset retirement obligations of $192 thousand for the assets acquired. Substantially all of the value of the Liberty County Properties acquired consists of mature proved developed producing reserves and proved developed non-producing reserves. Following is a summary of the amounts recorded for the assets acquired:

		Amount
		(in thousands)
Amounts incurred:		
Value of 67,254 shares issued	$	285
Transaction costs		41
Total consideration paid		326
Asset retirement obligations assumed		192
Total amount incurred	$	518

3. REAL ESTATE HELD FOR SALE

The Company owns a 14-acre tract in Riverton, Wyoming with a two-story, 30,400 square foot office building and an additional 13-acre parcel of land adjacent to the building. The building served as the Company's corporate headquarters until 2015 and is currently being leased to government agencies and other non-affiliated companies. During the year ended December 31, 2020, the Company made the decision to sell the land and building and began a process to determine the price at which it would list the property for sale. The process included obtaining an appraisal, analyzing operating statements for the building, reviewing capitalization rates and consulting a large national commercial real estate company. The Company determined that the realizable value of the building and the building land was in the range of $700 thousand to $900 thousand and the realizable value of the additional land was in the range of $250 thousand to $300 thousand. A special committee of the board of directors was formed to evaluate the sales process. During 2020, the Company entered into an agreement with a large national commercial broker and a local broker in Riverton, Wyoming to sell the building and the land. The following are the pre-impairment carrying amounts and the estimated net proceeds, and a calculation of the loss recognized as a component of other income and expense in the consolidated statement of operations, relating to the property:

	Amount
	(in thousands)
Pre-impairment carrying value of real estate held for sale:	
Building	$ 720
Building improvements	276
Building land	380
Additional land	653
Total	$ 2,029
Fair value of real estate held for sale:	
Estimated sales price of building and land	$ 800
Estimated sales price of additional land	275
Estimated cost to sell	(100)
Estimated net proceeds	$ 975
Loss recognized on real estate assets held for sale	$ 1,054

4. REVENUE RECOGNITION

The Company's revenues are primarily derived from its non-operated 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'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.

During the year ended December 31, 2020, the Company acquired operated oil and gas producing properties. The Company sells its oil production at the delivery point specified in the contract and collects an agreed-upon index price, net of pricing differentials. The purchaser takes custody, title and risk of loss of the oil at the delivery point; therefore, control passes at the delivery point. The Company recognizes revenue at the net price received when control transfers to the purchaser. Natural gas and natural gas liquid ("NGL") are sold at the lease location, which is generally when control of the natural gas and NGL transfers to the purchaser, and revenue is recognized as the amount received from the purchaser.

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 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 statements of operations were reported gross for the years ended December 31, 2020 and 2019, as the gross amounts were known.

The Company disaggregates revenues from its share of revenue from the sale of oil and natural gas and liquids by state. The Company does not disaggregate revenues further by operated revenues and non-operated revenues because operated revenues accounted for only 6.1% of total revenues in 2020. The Company's revenues in its North Dakota, Texas and other regions for the years ended December 31, 2020 and 2019, are presented in the following table:

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in thousands)	
Revenue:		
North Dakota		
Oil	$ 1,240	$ 2,449
Natural gas and liquids	102	177
Total	1,342	2,626
Texas		
Oil	875	3,700

Natural gas and liquids	82	247
Total	957	3,947
Other		
Oil	12	-
Natural gas and liquids	19	-
Total	31	-
Combined Total	$ 2,330	$ 6,573

5. LEASES

On January 1, 2019, the Company adopted ASC 842 using the modified retrospective approach. 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 years ended December 31, 2020 and 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 under the following captions in the consolidated balance sheets at December 31, 2020 and 2019:

	December 31, 2020	December 31, 2019
	(in thousands)	
Right of use asset balance		
Operating lease	$ 127	$ 179
Lease liability balance		
Short-term operating lease	$ 65	$ 58
Long-term operating lease	78	142
	$ 143	$ 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, Texas office lease, which has a lease term of one year. Beginning in March 2020, the Company subleased its Denver, Colorado office and recognized sublease income.

	December 31,	
	2020	2019
	(in thousands)	
Operating lease cost	$ 74	68
Short-term lease cost	22	15
Sublease income	(41)	-
Total lease costs	$ 55	$ 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,	
	2020	2019
	(in thousands)	
Weighted average lease term (years)	2.1	3.1
Weighted average discount rate	8.75%	8.75%

The future minimum lease commitments as of December 31, 2020 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, 2020
	(in thousands)
2021	75
2022	76
2023	6
Total lease payments	$ 157
Less: imputed interest	(14)
Total lease liability	$ 143

As discussed in *Note 3- Real Estate Held for Sale*, the Company owns a 14-acre tract in Riverton, Wyoming with a two-story, 30,400 square foot office building. The Company recognized a loss on real estate held for sale related to the building and land during the year ended December 31, 2020 of $1,054 thousand, of which $651 thousand related to the building and land subject to the operating leases. The building is not depreciated while it is held for sale. The net capitalized cost of the building and the land subject to operating leases at December 31, 2020 and 2019 are as follows:

	December 31,	
	2020	2019
	(in thousands)	
Building subject to operating leases	$ 4,654	$ 4,654
Land	380	380
Less: accumulated depreciation	(3,658)	(3,599)
Loss on leased real estate held for sale	(651)	-
Building subject to operating leases, net	$ 725	$ 1,435

The future lease maturities of the Company's operating leases as of December 31, 2020 are presented in the table below. Such maturities are reflected at undiscounted values to be received on an annual basis.

	December 31, 2020
	(in thousands)
2021	161
2022	165
2023	169
2024	163
Remaining through June 2029	695
Total lease maturities	$ 1,353

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, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Operating lease income	$ 213	$ 207
Operating lease expense	(181)	(157)
Depreciation	(59)	(122)
Rental property loss, net	$ (27)	$ (72)

6. OIL AND NATURAL GAS PRODUCING ACTIVITIES

Divestitures

There were no divestures of oil and natural gas producing properties during the year ended December 31, 2020. In December 2019, the Company completed the sale of its interest in four Texas wells for $75 thousand in cash and the 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 as of December 31, 2020, the Company used $39.57 per barrel for oil and $1.99 per one million British Thermal Units (MMbtu) for natural gas (as further adjusted for property, specific gravity, quality, local markets and distance from markets) to compute the future cash flows of the Company's producing properties. The discount factor used was 10%.

The Company recorded ceiling test write-downs of its oil and natural gas properties of $2.9 million during the year ended December 31, 2020, due to a reduction in the value of proved oil and natural gas reserves, primarily as a result of a decrease in crude oil prices and the performance of a South Texas well drilled in the prior year. In addition, the Company evaluated its unevaluated property and recorded a reclassification to the depletable base of the full cost pool of $2.1 million during the year ended December 31, 2020, related to a reduction in value of certain of its acreage.

7. DEBT

On September 24, 2020, the Company entered into a $375 thousand secured promissory note with APEG Energy II LP, which entity Patrick E. Duke, a former director of the Company, had shared voting power and shared investment power over ("APEG II" and the "Note"). The Note accrues interest at 10% per annum and matures on September 24, 2021. The Note is secured by the Company's wholly owned subsidiary, Energy One's oil and natural gas producing properties. In the event that the Note is repaid prior to the maturity date, there is a prepayment penalty of 10% of the principal amount of the Note less accrued interest. During the year ended December 31, 2020, the Company recorded interest expense related the Note of $10 thousand. At December 31, 2020, APEG II held approximately 18% of the Company's outstanding common stock; however, in January 2021, APEG II distributed all shares of the Company's common stock to its owners.

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.

The credit facility was fully repaid at March 1, 2019 and on July 30, 2019, matured and was terminated. Interest expense for the year ended December 31, 2019 was $20 thousand, including the amortization of debt issuance costs of $7 thousand. The weighted average interest rate on the credit facility was 8.75% for the period until maturity in 2019. During 2020 and 2019, APEG II was involved in litigation with the Company and its former Chief Executive Officer, as described in *Note 9-Commitments, Contingencies and Related Party Transactions.*

8. 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, market risk premiums, 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, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Balance, beginning of year	$ 819	$ 939
Accretion	43	22
Sold/Plugged	(12)	(130)
Acquired	558	2
Revisions	-	(14)
Liabilities incurred	-	-
Balance, end of year	$ 1,408	$ 819

9. COMMITMENTS, CONTINGENCIES, AND RELATED PARTY TRANSACTIONS

Litigation

In July 2020, the Company received a request for arbitration from its former Chief Executive Officer, David Veltri claiming that it breached his employment agreement. The Company intends to vigorously contest this matter and believe these claims are without merit. The employment agreement requires that any disputes be submitted to binding arbitration. The Company has insurance for these types of claims and has reported the request for arbitration to its insurance carrier. The Company believes it is probable that it will incur future defense costs in this matter and has accrued $100 thousand at December 31, 2020, representing the amount of the Company's responsibility for costs under the insurance policy.

APEG II Litigation and Litigation with Former Chief Executive Officer

From February 2019 until August 2020, the Company was involved in litigation with its former Chief Executive Officer, David Veltri and its largest shareholder, APEG Energy II, L.P. ("APEG II") and APEG II's general partner, APEG Energy II, GP (together with APEG II, "APEG"). APEG owns approximately 18% of the Company's outstanding common stock at December 31, 2020. In addition, Patrick E. Duke, a former director of the Company, had shared voting and shared investment power over APEG. The litigation arose as a result of a vote at the February 25, 2019 board of directors meeting to terminate Mr. Veltri for using Company funds outside of his authority and for other reasons (the "Texas Litigation"). In a separate lawsuit, APEG initiated a shareholder derivative action in Colorado against Mr. Veltri due to his refusal to recognize the Board's decision to terminate him (the "Colorado Litigation"). The Company was named as a nominal defendant in the Colorado Litigation. Through December 31, 2020, the Company has incurred legal costs of approximately $1.3 million related to the litigation. The Colorado litigation was dismissed in May 2020 and the Texas Litigation was dismissed in August 2020. The Company has accrued $383 thousand for reimbursement of APEG's legal costs in the Colorado and Texas Litigation, which was paid on March 4, 2021 through the issuance of 90,846 shares of our restricted common stock (see also *Note 16 - Subsequent Events*).

In the Texas Litigation the Audit Committee intervened by filing a motion to remove Mr. Veltri's signature authority over the Company's bank accounts and engaging an independent accounting firm to conduct a forensic accounting investigation. The forensic accounting investigation and the Company's internal investigation, identified numerous 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 $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 in 2019.

In the Colorado Litigation, the United States District Court for the District of Colorado ("the Colorado Federal Court") granted injunctive relief to APEG II against Mr. Veltri and issued an order appointing C. Randel Lewis as the Company's custodian to serve as its Interim Chief Executive Officer and to serve on the Board as Chairman. Mr. Lewis, as custodian, was ordered to act in place of the Board to appoint one independent director to replace a director who had resigned. Mr. Lewis appointed Catherine J. Boggs to serve as an independent director until the Company's 2019 annual meeting of shareholders, which was held on December 10, 2019. Following such annual meeting, the Board appointed Ryan L. Smith, the Company's Chief Financial Officer to serve as its Chief Executive Officer, replacing Mr. Lewis in that role.

10. 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 December 31, 2020, the Company redeemed all then 50,000 shares outstanding of Series A Convertible Preferred Stock (the "Preferred Stock") by making a cash payment of $2.0 million and issuing 328,000 shares of its common stock, which at the date of the redemption had a value of $3.68 per share for a total redemption price of $3.2 million. The liquidation preference on the date of redemption was $3.6 million. The difference between the redemption price and the liquidation preference of the preferred stock was included as a reduction of the net loss available to common shareholders in the calculation of loss per share.

The Company had issued the 50,000 shares of Preferred Stock on February 12, 2016 to Mt. Emmons Mining Company ("MEM"), a subsidiary of Freeport McMoRan, 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 of $2 million. The Preferred Stock liquidation preference, initially $2 million, increased by quarterly dividends of 12.25% per annum (the "Adjusted Liquidation Preference"). At the option of the holder, each share of Preferred Stock initially could have been 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. The Conversion Rate was 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, the aggregate number of shares of Common Stock issuable upon conversion was 79,334 shares, which was the maximum number of shares issuable upon conversion.

The Preferred Stock was senior to other classes or series of shares of the Company with respect to dividend rights and rights upon liquidation. No dividend or distribution could 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 had been declared and paid on the Preferred Stock on an as-converted basis. The Preferred Stock did 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 had the right to approve specified matters as set forth in the certificate of designation and had the right to require the Company to repurchase the Preferred Stock in the event of a change of control, which had not been triggered prior to the redemption on December 31, 2020. Concurrent with entry into the Acquisition Agreement and the Series A Purchase Agreement, the Company and MEM entered into an Investor Rights Agreement, which provided MEM rights to certain information and Board observer rights, which was terminated on December 31, 2020. MEM had agreed that it, along with its affiliates, would not acquire more than 16.86% of the Company's issued and outstanding shares of common stock. In addition, MEM had 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.

11. SHAREHOLDERS' EQUITY

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, for a period of five years from the final closing date of June 21, 2017. The warrants include anti-dilution rights. The total net proceeds received by the Company were approximately $1.32 million. The fair value of the warrants upon issuance were $1.24 million, with the remaining $0.08 million being attributed to common stock. On September 29, 2020, the Company received proceeds of $565 thousand related to the exercise of warrants to purchase 50,000 shares of 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 $95 thousand and $73 thousand at December 31, 2020 and 2019, respectively

Pursuant to the original warrant agreement, 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. The warrant exercise price was further reduced to the floor of $3.92 per share during the year ended December 31, 2020, as a result of the underwritten offering of 1,150,000 shares of common stock which was completed on November 16, 2020.

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 $0 and $41 thousand for the years ended December 31, 2020 and 2019, respectively. As of December 31, 2019, all stock options had vested. No stock options were granted, forfeited or exercised; however, stock options to purchase 166 shares expired during the year ended December 31, 2020. During the year ended December 31, 2019, no stock options were granted, expired or exercised; however, as the result of an employee termination 500 unvested stock options were forfeited. Presented below is information about stock options outstanding and exercisable as of December 31, 2020 and 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:

	2020		2019	
	Shares	Price (1)	Shares	Price (1)
Outstanding, beginning of year	31,533	$ 66.04	32,033	$ 65.20
Granted	-	-	-	-
Forfeited	-	-	(500)	11.60
Expired	(166)	-	-	-
Exercised	-	-	-	-
Outstanding, end of year	31,367	$ 64.78	31,533	$ 66.04
Exercisable, end of year	31,367	$ 64.78	31,533	$ 66.04

(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			Remaining		Weighted Average
Number of	Range		Weighted	Contractual	Number of	Exercise
Shares	Low	High	Average	Term (years)	Shares	Price
16,500	$ 7.20	$ 11.60	$ 10.00	6.8	16,500	$ 10.00
10,622	90.00	124.80	106.20	3.3	10,622	106.20
2,913	139.20	171.00	147.39	1.4	2,913	147.39
1,332	226.20	251.40	232.48	2.9	1,332	232.48
31,367	$ 7.20	$ 251.40	$ 64.78	4.9	31,367	$ 64.78

In January 2020, the Company granted 48,000 restricted shares of common stock to the Company's Chief Executive Officer as a discretionary bonus, of which 24,000 shares vest after one year and 24,000 vest after two years. In addition, the Company granted a total of 23,000 restricted shares of common stock to members of the board of directors, which vest on January 28, 2021. For the year ended December 31, 2020, the Company recognized $211 thousand in stock compensation expense related to these restricted stock grants. At December 31, 2020, the unrecognized expense related to the restricted stock grants was $137 thousand.

12. INCOME TAXES

The components of the income tax provision for the years ended December 31, 2020 and 2019 include the following:

	2020	2019
	(in thousands)	
Current income tax expense (benefit)	$ (42)	$ -
Deferred income taxes	-	-
	$ (42)	$ -

The current income tax benefit for the year ended December 31, 2020 represents a refund of alternative minimum tax credit carryovers received in 2020.

The Company incurred net losses for each of the years ended December 31, 2020 and 2019, 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:

	2020	2019
	(in thousands)	
Income tax benefit at federal statutory rate	$ (1,361)	$ (115)
State income tax benefit, net of federal impact	(35)	(32)
Change in state tax rate, net of federal benefit	(32)	331
Change in value of warrant	5	(74)
Percentage depletion carryover	(3)	9
Prior year true up	154	52
Other	(53)	23
Increase (decrease)in valuation allowance	1,283	(194)
Income tax expense (benefit)	$ (42)	$ -

The components of deferred tax assets and liabilities as of December 31, 2020 and 2019 are as follows:

	2020	2019
	(in thousands)	
Deferred tax assets:		
Net operating loss carryover (1)	$ 5,154	$ 4,098
Property and equipment	3,939	3,468
Percentage depletion and contribution carryovers (1)	1,855	1,833
Alternative minimum tax credit carryover (1)	-	42
Equity method investment and other	246	615
Deferred compensation liability	7	41
Asset retirement obligations	315	181
Stock-based compensation	115	68
Lease obligations	32	44
Total deferred tax assets	11,663	10,390
Deferred tax liabilities:		
Lease assets	(28)	(40)

Total deferred tax liabilities	(28)	(40)
Net deferred tax assets	11,635	10,350
Less valuation allowance	(11,635)	(10,350)
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, 2020, the Company has approximately $8.9 million in 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, 2020, the Company has approximately $9.2 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, 2020 and 2019, 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, 2020 and 2019, 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, 2020 and 2019 related to uncertain tax positions.

13. 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 prior to redemption, and unvested shares of restricted common stock. When the Company recognizes a net loss, as was the case for the years ended December 31, 2020 and 2019, 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, 2020 and 2019 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:

	2020	2019
	(in thousands except per share data)	
Net loss	$ (6,439)	$ (550)
Dividend on series A preferred stock	(421)	(372)
Gain on redemption of series A preferred stock	441	-
Net loss applicable to common shareholders	$ (6,419)	$ (922)
Basic weighted-average common shares outstanding	1,628	1,340
Dilutive effect of potentially dilutive securities	-	-
Diluted weighted-average common shares outstanding	1,628	1,340
Basic net loss per share	$ (3.94)	$ (0.69)
Diluted net loss per share	$ (3.94)	$ (0.69)

For the years ended December 31, 2020 and 2019, potentially dilutive securities excluded from the calculation of weighted average shares because they were anti-dilutive are as follows:

	2020	2019
	(in thousands)	
Stock options	31	31
Unvested shares of restricted stock	71	-
Warrants	50	100
Series A Preferred Stock	-	79
Total	152	210

14. FAIR VALUE MEASUREMENTS

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 2020. The Company worked with a third-party valuation expert estimating the value of the warrants at December 31, 2020 and 2019, with the following assumptions:

		2020		2019
Number of warrants outstanding		50,000		100,000
Expiration date		June 21, 2022		June 21, 2022
Exercise price	$	3.92	$	11.30
Stock price	$	3.68	$	3.00
Dividend yield		0%		0%
Average volatility rate (1)		120%		80%
Probability of down-round event (2)		0%		25%
Risk free interest rate		0.11%		1.59%

(1) The average volatility represents the Company's volatility measurement, the observed volatility of our peer group over a similar period, and the stock market volatility as of the valuation date.

(2) Represents the estimated probability of a future down-round event during the remaining term of the warrants.

At December 31, 2020, the Company used the average value calculated by the Black-Scholes model as opposed to a Monte Carlo model, because the strike price is set at the floor of $3.92 and therefore cannot be rounded down further. At December 31, 2019, the Company used the average value of $73 thousand with a range from $60 thousand to $120 thousand. An increase in any of the inputs would cause an increase in the fair value of the warrants. Likewise, a decrease in any input would cause a decrease in the fair value of the warrants.

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		2,421,180		495,816
Quoted market price	$	0.07455	$	0.0000
Fair value	$	180,500	$	-

Other Assets and Liabilities

The Company evaluates the fair value on a non-recurring basis of properties acquired in business combinations, asset acquisitions and the related asset retirement obligations. The fair value of the oil and gas properties is determined based upon estimated future discounted cash flow, a Level 3 input, using estimated production which we reasonably expect, and estimated prices adjusted for differentials. Unobservable inputs include estimated future oil and natural gas production, prices, operating and development costs, and a discount rate of 10%, all Level 3 inputs within the fair value hierarchy.

The Company evaluates the fair value on a non-recurring basis of its Riverton, Wyoming real estate assets when circumstances indicate that the value has been impaired. The Company evaluated the fair value of the real estate assets based upon offers we have received from potential purchasers of the property, the expected annual net operating income of the building, estimated capitalization rates for properties in rural areas and values for vacant land based on comparable sales, all Level 3 inputs within the fair value hierarchy.

The carrying value of financial instruments included in current assets and current liabilities approximate fair value due to the short-term nature of those instruments.

Recurring Fair Value Measurements

Recurring measurements of the fair value of assets and liabilities as of December 31, 2020 and 2019 are as follows:

	December 31, 2020				December 31, 2019			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
			(in thousands)					
Assets:								
Marketable Equity Securities	181	-	-	181	307	-	-	307
Total	$ 181	$ -	$ -	$ 181	$ 307	$ -	$ -	$ 307
Liabilities:								
Warrants	-	-	95	95	-	-	73	73
Total	$ -	$ -	$ 95	$ 95	$ -	$ -	$ 73	$ 73

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

	Year Ended December 31,	
	2020	2019
	(in thousands)	
Fair value of Level 3 instruments liabilities at beginning of period	$ 73	$ 425
Net unrealized loss (gain) on warrant valuation	22	(352)
	-	
Fair value of Level 3 instruments liabilities at end of period	$ 95	$ 73

15. 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, 2020 and 2019 are provided in the table below:

	2020	2019
	(in thousands)	
Proved property acquisition	$ 1,851	$ -
Unproved property acquisition	-	12
Development	441	305
Exploration	-	552
Total	$ 2,292	$ 869

Capitalized Costs

The following table presents the Company's capitalized costs associated with oil and natural gas producing activities as of December 31, 2020 and 2019:

	2020	2019
	(in thousands)	
Oil and Natural Gas Properties:		
Unevaluated properties:		
Unproved leasehold costs	$ 1,597	$ 3,741
Evaluated properties in full cost pool	93,549	89,113
Less accumulated depletion and ceiling test impairment	(87,708)	(84,400)
Net capitalized costs	$ (7,438)	$ 8,454

The Company incurred ceiling test write-downs of its oil and natural gas properties of $2.9 million during the year ended December 31, 2020 due to a reduction in the value of its proved oil and natural gas reserves primarily as the result of a decrease in crude prices and the performance of a South Texas well drilled in the prior year. Depletion and amortization was $363 thousand ($4.55 per BOE) and $671 thousand ($4.63 per BOE) for the years ended December 31, 2020 and 2019, 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 $1.6 million and $3.7 million at December 31, 2020 and 2019, 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. During the year ended December 31, 2020, the Company evaluated its unevaluated property and recorded a reclassification to the depletable base of the full cost pool of $2.1 million related to a reduction in value of certain of its acreage. During 2019, 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.

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, 2020 and 2019:

	2020	2019
	(in thousands)	
Oil and natural gas sales	$ 2,330	$ 6,573
Lease operating expense	(1,535)	(1,848)
Production taxes	(168)	(429)
Depletion and amortization	(356)	(671)
Impairment of oil and natural gas properties	(2,943)	-
Results of operations from oil and natural gas producing activities	$ (2,672)	$ 3,625

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, 2020 and 2019 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Don Jacks, PE. The estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission. All of the Company's estimated proved reserves are located in the United States.

As of December 31, 2020, and 2019, the Company had no proved undeveloped reserves. All proved reserves were proved developed producing and proved developed non-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, 2020 and 2019:

	2020		2019	
	Oil (bbls)	Gas (mcfe) (1)	Oil (bbls)	Gas (mcfe) (1)
Total proved reserves:				
Reserve quantities, beginning of year	807,505	1,129,258	751,260	737,998
Revisions of previous estimates	(248,770)	(22,895)	99,352	511,969
Discoveries and extensions	-	-	72,907	101,892
Purchases of minerals in place	477,479	686,670		
Sale of minerals in place	-	-	(5,924)	(13,083)
Production	(60,469)	(116,085)	(110,090)	(209,518)
Reserve quantities, end of year	975,745	1,676,948	807,505	1,129,258

(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, 2020 included the following:

- The downward revisions of previous estimates of 252,586 BOE were primarily attributable to revisions due to lower pricing used in the estimate of proved reserves at December 31, 2020 and the higher than estimated decline in performance of wells drilled in our South Texas properties in 2019.
- Purchases of reserves in place represent the reserves added as a result of the acquisitions of New Horizon Resources LLC, certain properties from FieldPoint Production Company, and certain properties from Newbridge Resources completed during the year.

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:

		2020		2019
Oil per Bbl	$	39.57	$	55.69
Gas per Mcfe [(1)]	$	1.99	$	2.58

(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, 2020 and 2019:

		2020		2019
		(in thousands)		
Future cash inflows	$	39,090	$	45,528
Future cash outflows:				
Production costs		(24,189)		(21,435)
Development costs		(302)		-
Income taxes		(142)		(3,747)
Future net cash flows		14,457		20,436
10% annual discount factor		(5,871)		(9,998)
Standardized measure of discounted future net cash flows	$	8,586	$	10,348

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, 2020 and 2019 are as follows:

		2020		2019
		(in thousands)		
Standardized measure, beginning of year	$	10,348	$	11,599
Sales of oil and natural gas, net of production costs		(627)		(4,296)
Net changes in prices and production costs		(8,487)		(2,499)
Changes in estimated future development costs		(302)		-
Extensions and discoveries		-		2,231
Purchases of minerals in place		5,841		-
Sale of minerals in place		-		(83)
Revisions in previous quantity estimates		(1,148)		2,130
Previously estimated development costs incurred		-		-
Net changes in income taxes		1,649		(299)
Accretion of discount		855		1,068
Changes in timing and other		457		497
Standardized measure, end of year	$	8,586	$	10,348

16. SUBSEQUENT EVENTS

Underwritten offering

On February 11, 2021, the Company sold 1,131,500 shares of its common stock in an underwritten offering at a public offering price of $5.10 per share (the "Offering"). The Offering closed on February 17, 2021. The net proceeds to the Company from the Offering, after deducting the underwriting discounts and commissions and Offering expenses, were $5.3 million. The Company intends to use the net proceeds from the offering for general corporate purposes, capital expenditures, working capital, and potential acquisitions of oil and gas properties.

Conversion of Secured Note Payable

On March 4, 2021 the Company entered into a Debt Conversion Agreement with APEG II. Pursuant to the Debt Conversion Agreement, APEG II converted a total of $413 thousand, representing the principal of a September 2020 Secured Promissory Note in the principal amount of $375 thousand and accrued interest of $38 thousand into 97,962 unregistered shares of its common stock. The number of shares was based on a conversion price of $4.21 per share, a 9.9%

discount to the ten-day volume weighted average price of its common stock for the ten days immediately preceding the signing of the Debt Conversion Agreement (the "VWAP Discount Price").

Reimbursement of APEG II Legal Fees

Also, on March 4, 2021, APEG II entered into a Subscription Agreement with the Company, whereby APEG II subscribed to purchase 90,846 unregistered shares of the Company's common stock for an aggregate of $383 thousand based on the VWAP Discount Price. The $383 thousand subscription price was paid by way of forgiveness by APEG II of the same amount of funds owed by the Company for reimbursement of APEG II's legal costs in connection with certain shareholder derivative actions brought by APEG II against the Company and its former Chief Executive Officer in Colorado and Texas, which were dismissed in May 2020 and August, respectively.

Commodity Derivative Contract

On March 9, 2021, the Company entered into a commodity derivative contract to fix the price of 100 barrels of crude oil per day from March 1 to December 31, 2021 at $61.90 based on the calendar month average of West Texas Intermediate Crude Oil.

Restricted share issuance

In January 2021, the Company's board of directors granted 100,000 restricted shares to the Chief Executive Officer, which vest equally over four years. In addition, the Company's four independent directors were each granted 10,000 restricted shares which vest on January 28, 2022.

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 included in Item 8 of this report under " Financial Statements and Supplementary Data":

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:

		Incorporated by Reference				
Exhibit No.	Description	Form	File No.	Exhibit	Filing Date	Filed Herewith
1.1	Placement Agency Agreement, dated September 29, 2020, between the Company and Kingswood Capital Markets, division of Benchmark Investments, Inc.	8-K	000-06814	1.1	October 2, 2020	
1.2	Underwriting Agreement, dated February 11, 2021, by and between U.S. Energy Corp. and Kingswood Capital Markets, division of Benchmark Investments, Inc.	8-K	000-06814	1.1	February 16, 2021	
3.1	Amended and Restated Articles of Incorporation	10-K	000-06814	3.1	March 30, 2020	
3.2	Certificate of Designation for Series A Convertible Preferred Stock (incorporated by reference from Exhibit A to Exhibit 3.1)	10-K	000-06814	3.1	March 30, 2020	
3.3	Amended and Restated Bylaws, dated as of August 5, 2019	8-K	000-06814	3.2	August 9, 2019	
4.1*	Description of Securities of the Registrant					X
4.2	Specimen Certificate for Common Stock, par value $0.01 per share	S-3	333-162607	4.9	October 20, 2009	
4.3	Common Stock Purchase Warrant Initially Exercisable June 21, 2017	8-K	000-06814	4.1	December 22, 2016	
10.1†	USE 2001 Officers' Stock Compensation Plan	10-K	000-06814	4.21	September 13, 2002	
10.2†	2001 Incentive Stock Option Plan (amended in 2003)	10-K	000-06814	4.2	April 15, 2005	
10.3†	2008 Stock Option Plan for Independent Directors and Advisory Board Members	10-K	000-06814	4.3	March 13, 2009	
10.4†	U.S. Energy Corp. Employee Stock Ownership Plan (adopted December 2011)	S-8	333-180735	4.1	April 13, 2012	

10.5†	U.S. Energy Corp. Amended and Restated 2012 Equity Performance and Incentive Plan	8-K	000-06814	10.1	June 10, 2020	
10.6†	Form of Grant to the 2012 Equity and Performance Incentive Plan	10-K	000-06814	10.5.1	March 18, 2013	
10.7†	Executive Employment Agreement – Ryan Smith (effective March 5, 2020)	8-K	000-06814	10.1	March 10, 2020	
10.8†	Form of Option Agreement between U.S. Energy Corp. and its directors	10-K	000-06814	10.8(i)	March 28, 2018	
10.9†	Form of Incentive Option Agreement between U.S. Energy Corp. and its executive officers	10-K	000-06814	10.8(j)	March 28, 2018	
10.10†	Form of Indemnity Agreement between U.S. Energy Corp. and its directors and officers	10-K	000-06814	10.8(k)	March 28, 2018	
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	8-K	000-06814	10.1	March 5, 2020	
#10.12	Asset Purchase Agreement dated September 25, 2020, by and among U.S. Energy Corp. as Buyer, and Mr. Randolph N. Osherow, as Chapter 7 trustee in the Bankruptcy Case of FieldPoint Petroleum Corporation	S-1	333-249738	10.16	October 30, 2020	
10.13	$375,000 Secured Promissory Note dated September 24, 2020 entered into by U.S. Energy Corp., to evidence amounts owed to APEG Energy II, L.P.	S-1	333-249738	10.17	October 30, 2020	
#10.14	Form of Securities Purchase Agreement, dated September 30, 2020, by and between the Company and the Purchasers thereunder	8-K	000-06814	10.1	October 2, 2020	
10.15†	Form of Lock-Up Agreements for September 2020 Offering	8-K	000-06814	10.2	October 2, 2020	
#10.16	Purchase and Sale Agreement dated November 9, 2020, by and among New Horizon Resources LLC, as Buyer, and Newbridge Resources LLC as Seller	8-K	000-06814	10.1	November 9, 2020	
10.17	Exchange Agreement by and between U.S. Energy Corp. and Mt. Emmons Mining Company dated as of December 31, 2020	8-K	000-06814	10.1	January 7, 2021	
10.18†	Form of Lock-Up Agreement	8-K	000-06814	10.1	February 16, 2021	
10.19	Debt Conversion Agreement by and between U.S. Energy Corp. and APEG Energy II, L.P. dated as of March 4, 2021	8-K	000-06814	10.1	March 9, 2021	
10.20	Subscription Agreement of APEG Energy II, L.P., dated as of March 4, 2021	8-K	000-06814	10.2	March 9, 2021	
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 the Registrant					X
23.1*	Consent of Independent Registered Public Accounting Firm (Plante & Moran, PLLC)					X
23.2*	Consent of Reserve Engineer (Don Jacks, PE)					X
31.1*	Certification of Chief Executive Officer and principal financial officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002					X
32.1**	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002					X
99.1*	Reserve Report Summary (Don Jacks, PE)					X
101.INS*	XBRL Instance Document					X
101.SCH*	XBRL Schema Document					X
101.CAL*	XBRL Calculation Linkbase Document					X
101.DEF*	XBRL Definition Linkbase Document					X
101.LAB*	XBRL Label Linkbase Document					X
101.PRE*	XBRL Presentation Linkbase Document					X

* Filed herewith.

** Furnished herewith.

† Exhibit constitutes a management contract or compensatory plan or agreement.

Certain schedules, annexes, and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. A copy of any omitted schedule or exhibit will be furnished supplementally to the Securities and Exchange Commission upon request; provided, however, that U.S. Energy Corp. may request confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended, for any schedule or exhibit so furnished.

Item 16. Form 10-K Summary

None

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 26, 2021

By: */s/ Ryan L. Smith*
RYAN L. SMITH, President, Chief Executive Officer, Chief Financial Officer and Director
(*Principal Executive Officer and Principal 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 26, 2021

By: */s/ Ryan L. Smith*
RYAN L. SMITH, President, Chief Executive Officer, Chief Financial Officer and Director
(*Principal Executive Officer and Principal Financial and Accounting Officer*)

By: */s/ James W. Denny*
James W. Denny, Director

Date: March 26, 2021

By: */s/ Randall D. Keys*
Randall D. Keys, Director

Date: March 26, 2021

By: */s/ Javier F. Pico*
JAVIER F. PICO, Director

Date: March 26, 2021

By: */s/ D. Stephen Slack*
D. Stephen Slack, Director

EXHIBIT 4.1

DESCRIPTION OF SECURITIES
REGISTERED PURSUANT TO SECTION 12 OF
THE SECURITIES EXCHANGE ACT OF 1934

The following summary describes the common stock of U.S. Energy Corp., a Wyoming corporation (" U.S. Energy" or the "Company"), which common stock is registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Only the Company's common stock is registered under Section 12 of the Exchange Act.

Description of Common Stock

The following description of our common stock is a summary and is qualified in its entirety by reference to our Amended and Restated Articles of Incorporation and our Amended and Restated Bylaws, which are incorporated by reference as exhibits to this Annual Report on Form 10-K, and by applicable law (including the Wyoming Business Corporation Act). For purposes of this description, references to "U.S. Energy," "we," "our" and "us" refer only to the Company and not to its subsidiaries.

Authorized Capitalization

Our authorized capital stock consists of an unlimited number of shares of common stock with a $0.01 par value per share and 100,000 shares of preferred stock, $0.01 par value per share.

The terms of our preferred stock are not included herein as such preferred stock is not registered under Section 12 of the Exchange Act.

Common Stock

Voting Rights. Holders of common stock are entitled to one vote for each share held on all matters submitted to a vote of stockholders, except that cumulative voting in the election of directors is permitted (as discussed below).

The presence of the persons entitled to vote a majority of the outstanding voting shares on a matter before the stockholders constitute the quorum necessary for the consideration of the matter at a stockholders' meeting.

Except as otherwise required by law, the Amended and Restated Articles of Incorporation, or any certificate of designation, (i) at all meetings of stockholders for the election of directors, a plurality of votes cast are sufficient to elect such directors; (ii) any other action taken by stockholders are valid and binding upon the Company if the number of votes cast in favor of the action exceeds the number of votes cast in opposition to the action, at a meeting at which a quorum is present; and (iii) broker non-votes and abstentions are considered for purposes of establishing a quorum but not considered as votes cast for or against a proposal or director nominee.

In all elections for directors, every holder of the common stock has the right to vote in person, by proxy or by voting trustee under any voting trust, the number of shares of stock owned by him, her or it, for as many persons as there are directors to be elected, or to cumulate such shares and to give one candidate as many votes equal to the number of directors multiplied by the number of his, her or its shares of stock or to distribute them on the same principle among as many candidates as he, she or it desires.

Dividend Rights. Holders are entitled to receive dividends when and as declared by the Board of Directors out of funds legally available therefor. We may declare dividends in the future but we expect to retain most or all of our earnings and cash to fund investments and business development.

Liquidation and Dissolution Rights. Upon liquidation, dissolution or winding-up of the Company, and after payment to our creditors and preferred stockholders, if any, our assets will be divided pro rata on a share-for-share basis among the holders of our common stock, subject to the rights of any holders of preferred stock.

Consideration for Shares. Shares of common stock may be issued for such consideration and on such terms as determined by the Board of Directors, without stockholder approval.

Fully Paid Status. All outstanding shares of the Company's common stock are validly issued, fully paid and non-assessable.

Listing. Our common stock is listed and traded on The Nasdaq Capital Market under the symbol " USEG".

Other Matters. No holder of any shares of our common stock has a preemptive right to subscribe for any of our securities, nor are any shares of our common stock subject to redemption or convertible into other securities.

Anti-Takeover Effects of our Amended and Restated Articles of Incorporation and Wyoming Law

Our Amended and Restated Articles of Incorporation provide for the issuance of up to an unlimited number of shares of common stock, par value $0.01 per share. Our authorized but unissued shares of common stock will be available for future issuance without stockholder approval. These additional shares may be utilized for a variety of corporate purposes, including future public offerings to raise additional capital, corporate acquisitions and employee benefit plans. Our board has the authority to issue an unlimited additional number of shares. The existence of unlimited authorized but unissued shares of common stock could render more difficult or discourage an attempt to obtain control of a majority of our common stock by means of a proxy contest, tender offer, merger or otherwise.

We may be or in the future we may become subject to Wyoming's control share law. The law focuses on the acquisition of a " controlling interest" which means the ownership of outstanding voting shares sufficient, but for the control share law, to enable the acquiring person to exercise the following proportions of the voting power of the corporation in the election of directors: (i) one-fifth or more but less than one-third, (ii) one-third or more but less than a majority, or (iii) a majority or more. The ability to exercise such voting power may be direct or indirect, as well as individual or in association with others. The effect of the control share law is that the acquiring person, and those acting in association with it, obtains only such voting rights in the control shares as are conferred by a resolution of the stockholders of the corporation, approved at a special or annual meeting of stockholders. The control share law contemplates that voting rights will be considered only once by the other stockholders. Thus, there is no authority to strip voting rights from the control shares of an acquiring person once those rights have been approved. If the stockholders do not grant voting rights to the control shares acquired by an acquiring person, those shares do not become permanent non-voting shares. The acquiring person is free to sell its shares to others. If the buyers of those shares themselves do not acquire a controlling interest, their shares do not become governed by the control share law. If control shares are accorded full voting rights and the acquiring person has acquired control shares with a majority or more of the voting power, any stockholder of record, other than an acquiring person, who has not voted in favor of approval of voting rights is entitled to demand fair value for such stockholder's shares.

Wyoming's control share law may have the effect of discouraging takeovers of the corporation. In addition to the control share law, Wyoming has a business combination law which prohibits certain business combinations between Wyoming corporations and "interested stockholders" for three years after the "interested stockholder" first becomes an "interested stockholder," unless the corporation's Board of Directors approves the combination in advance. For purposes of Wyoming law, an "interested stockholder" is any person who is (i) the beneficial owner, directly or indirectly, of ten percent or more of the voting power of the outstanding voting shares of the corporation, or (ii) an affiliate or associate of the corporation and at any time within the three previous years was the beneficial owner, directly or indirectly, of ten percent or more of the voting power of the then outstanding shares of the corporation. The definition of the term "business combination" is sufficiently broad to cover virtually any kind of transaction that would allow a potential acquiror to use the corporation's assets to finance the acquisition or otherwise to benefit its own interests rather than the interests of the corporation and its other stockholders. The effect of Wyoming's business combination law is to potentially discourage parties interested in taking control of the Company from doing so if it cannot obtain the approval of our Board of Directors.

Separately, our authorized but unissued shares of common stock and preferred stock are available for future issuance without stockholder approval, subject to any limitations imposed by the listing standards of The NASDAQ Capital Market. These additional shares may be used for a variety of corporate finance transactions, acquisitions and employee benefit plans. The existence of authorized but unissued and unreserved common stock and preferred stock could make more difficult or discourage an attempt to obtain control of us by means of a proxy contest, tender offer, merger or otherwise.

Anti-Takeover Effects of Our Amended and Restated Articles of Incorporation and Amended and Restated Bylaws

The following provisions of our Amended and Restated Articles of Incorporation, as amended, and Amended and Restated Bylaws could have the effect of delaying or discouraging another party from acquiring control of us and could encourage persons seeking to acquire control of us to first negotiate with our Board of Directors:

- cumulative voting in the election of directors, which gives majority shareholders a disproportionate ability to elect director candidates;
- the right of our Board of Directors to elect a director to fill a vacancy created by the expansion of the Board of Directors or the resignation, death or removal of a director, with our shareholders only allowed to fill such a vacancy if not filled by the board;
- the ability of our Board of Directors to alter our bylaws without obtaining shareholder approval; and
- the requirement that a special meeting of shareholders may be called only by (i) the President, (ii) the Board, or (iii) one or more written demands of the holders of twenty-five percent (25%) of all the votes entitled to be cast at the proposed special meeting.

Exhibit 21.1

SUBSIDIARIES

Energy One LLC, Wyoming, wholly-owned

New Horizon Resources, LLC, North Dakota wholly-owned

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in U.S. Energy Corp.'s Registration Statements on Form S-3 (No. 333-248906), Form S-1 (No. 333-249738) and Form S-8 (Nos. 333-108979, 333-166638, 333-180735, and 333-183911) of our report dated March 26, 2021 relating to the December 31, 2020 and 2019 consolidated financial statements of U.S. Energy Corp., which appears in this Annual Report on Form 10-K.

/s/ Plante & Moran, PLLC

Denver, Colorado
March 26, 2021

Exhibit 23.2

CONSENT OF DON JACKS, P.E.

I hereby consent to the inclusion in the Annual Report on Form 10-K prepared by U.S. Energy Corp. (the "Company") for the year ended December 31, 2020, of my report relating to certain estimated quantities of the Company's proved reserves of oil and natural gas, future net income and discounted future net income, effective December 31, 2020. I further consent to reference to me under Item 2 – Properties under the heading "Oil and Natural Gas" and Item 8, Note 15 of the Notes to Consolidated Financial Statements under the caption "Supplemental Oil and Natural Gas Reserves (Unaudited)." I further consent to the inclusion of my report dated February 1, 2021, containing my opinion on the proved reserves attributable to certain properties that the Company has represented that it has an interest in as of December 31, 2020, as an exhibit in the Annual Report and to the incorporation by reference of information from my Report into the Company's Registration Statements on Form S-3 (No. 333-248906), Form S-1 (No. 333-249738) and Form S-8 (Nos. 333-108979, 333-166638, 333-180735, and 333-183911).

Very truly yours,

/s/ Don Jacks

Don Jacks, P.E.

Exhibit 31.1

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

I, Ryan L. Smith, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: March 26, 2021

By: */s/ Ryan L. Smith*

Ryan L. Smith
Chief Executive Officer and Chief Financial Officer
(Principal Executive Officer and Principal Accounting/Financial Officer)

Exhibit 32.1

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

In connection with the Annual Report on Form 10-K of U.S. Energy Corp. (the "Company") for the year ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to my knowledge, that:

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

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

Date: March 26, 2021

By: */s/ Ryan L. Smith*
Ryan L. Smith
Chief Executive Officer and Chief Financial Officer
(Principal Executive Officer and Principal Accounting/Financial Officer)

Exhibit 99.1

ON POINT RESOURCES, LLC

3602 S. Garland Rd.
Enid, OK 73703
580-822-1145

2/1/21

US Energy Corporation
675 Bering, Ste. 100
Houston, TX 77057

Attn: Ryan Smith, CEO

Re: USEG 2020YE Reserve Report "as of" 1/01/21

Dear Ryan:

As per your request, I have evaluated remaining reserves for properties in Louisiana, North Dakota, New Mexico, Oklahoma, Texas, and Wyoming. This report includes 41 operated properties acquired effective December 1, 2020 of the fourth quarter from Newbridge Resources, LLC. The economic value as of January 1, 2021 uses the 4Q2020 average SEC price forecast assumptions confirmed by industry websites and documented in attachment. A summary table with each well's value along with other reports including the calculation of average OPEX through 11/30/20 and price differentials are attached in support this evaluation. This report is organized by USEG Region rather than by state as previously organized.

PROVED RESERVE VALUE "As Of" January 1, 2021

Total Proved Res	**(PV10%)**	**$ 8,662,382**	**(975,745 BO &**	**1,676,948 MCF Net)**

PDP RESERVE VALUE "As Of" January 1, 2021

Gulf Coast PDP	(PV10%)	$ 2,290,586	(182,955 BO &	0 MCF Net)
ND Bakken PDP	(PV10%)	$ 2,471,041	(410,444 BO &	491,978 MCF Net)
Other PDP	(PV10%)	$ 458,621	(36,667 BO &	28,193 MCF Net)
South TX PDP	(PV10%)	$ 742,424	(109,538 BO &	606,093 MCF Net)
West TX PDP	(PV10%)	$ 1,830,912	(131,263 BO &	550,684 MCF Net)
Total PDP Reserves	**(PV10%)**	**$ 7,793,584**	**(870,877 BO &**	**1,676,948 MCF Net)**

PDNP RESERVE VALUE "As Of" January 1, 2021

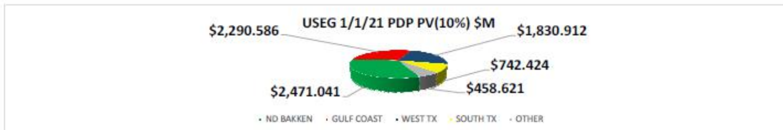
Gulf Coast PDNP	(PV10%)	$ 242,725	(54,917 BO &	0 MCF Net)
West TX PDNP	(PV10%)	$ 626,073	(49,951 BO &	0 MCF Net)
Total PDNP Reserves	**(PV10%)**	**$ 868,797**	**(104,868 BO &**	**0 MCF Net)**

USEG - 2020 YE SEC Price Forecast

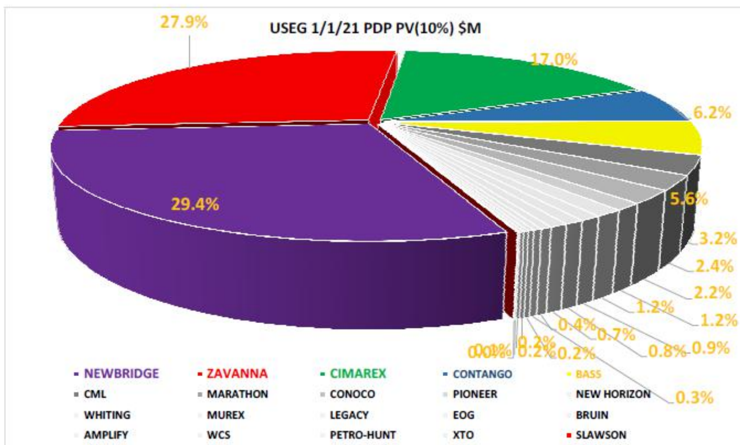
	SEC $/BO	SEC $/MCF
1/1/2020	$61.06	$2.05
2/1/2020	$51.56	$1.85
3/1/2020	$44.76	$1.73
4/1/2020	$20.31	$1.69
5/1/2020	$19.78	$1.69
6/1/2020	$35.44	$1.60
7/1/2020	$39.82	$1.69
8/1/2020	$40.27	$1.75
9/1/2020	$42.76	$2.24
10/1/2020	$38.72	$1.63
11/1/2020	$35.79	$3.04
12/1/2020	$44.55	$2.88
2020 YE Avg	**$39.57**	**$1.99**

Per R-S 1st of Month WTI & HH

DISTRIBUTION OF VALUE BY USEG REGION



DISTRIBUTION OF VALUE BY OPERATOR



USEG REGION	PDP Net MBO		PDP Net MMCF		USEG 1/1/21 PV(10%) $M	
ND BAKKEN	410.444	47.1%	491.978	29.3%	$2,471.041	31.7%
GULF COAST	182.955	21.0%	0.000	0.0%	$2,290.586	29.4%
WEST TX	131.263	15.1%	550.684	32.8%	$1,830.912	23.5%
SOUTH TX	109.538	12.6%	606.093	36.1%	$742.424	9.5%
OTHER	36.677	4.2%	28.193	1.7%	$458.621	5.9%
NEWBRIDGE	182.955	21.0%	0.000	0.0%	$2,290.586	29.4%
ZAVANNA	355.238	40.8%	361.878	21.6%	$2,172.263	27.9%
CIMAREX	103.582	11.9%	197.763	11.8%	$1,326.017	17.0%
CONTANGO	82.138	9.4%	580.872	34.6%	$480.557	6.2%
BASS	36.623	4.2%	0.000	0.0%	$439.794	5.6%
CML	25.336	2.9%	18.697	1.1%	$246.574	3.2%
MARATHON	11.886	1.4%	77.625	4.6%	$186.834	2.4%
CONOCO	0.190	0.0%	274.488	16.4%	$169.961	2.2%
PIONEER	7.509	0.9%	0.809	0.0%	$92.200	1.2%
NEW HORIZON	15.027	1.7%	82.780	4.9%	$90.064	1.2%
WHITING	11.066	1.3%	14.405	0.9%	$67.254	0.9%
MUREX	10.242	1.2%	8.255	0.5%	$60.675	0.8%
LEGACY	8.097	0.9%	0.000	0.0%	$55.900	0.7%
EOG	7.392	0.8%	10.699	0.6%	$34.685	0.4%
BRUIN	3.640	0.4%	2.252	0.1%	$25.201	0.3%
AMPLIFY	0.054	0.0%	28.193	1.7%	$18.828	0.2%
WCS	2.063	0.2%	6.524	0.4%	$15.294	0.2%
PETRO-HUNT	5.613	0.6%	7.957	0.5%	$12.695	0.2%
XTO	1.279	0.1%	3.142	0.2%	$5.175	0.1%
SLAWSON	0.948	0.1%	0.611	0.0%	$3.030	0.0%
Total	870.877		1,676.948		$7,793.584	

Monthly production was updated through 11/30/20 for almost all wells. A rigorous analysis of OPEX is provided as an attachment to this report based on net costs from USEG accounting that were "grossed up" for input into the economics program. OPEX was forecast with fixed and variable costs applied to the producing wells based on analysis of 12 months of costs through 11/30/20. A comparison of current actual costs to 4Q20 forecast OPEX costs is documented and was confirmed by USEG management. Consistent with prior reports, abandonment and salvage costs were not applied for lack of material impact based on analysis of longer well lives and confirmed with USEG management.

Wellhead oil price averaged $35.87/BO throughout the economic life of the properties and included deductions for transportation & quality. Wellhead gas price averaged $2.44/MCF throughout the economic life of the properties and included deductions for marketing, transportation & quality. Supporting documents for price assumptions, differentials and operating costs are included in support of this evaluation.

USEG PRODUCT PRICE DIFFERENTIALS
FOR SEC 4Q2021

ST	OPERATOR	Oil 4Q20 Differential $/BO	Gas & NGL 4Q20 Differential %
LA	AMPLIFY	$1.22	25%
ND	BRUIN	-$4.77	79%
ND	EOG	-$6.08	-4%
ND	MUREX	-$5.76	24%
ND	NEW HORIZON	-$8.29	-21%
ND	PETROHUNT	-$3.93	11%
ND	SLAWSON	-$6.96	-19%
ND	WHITING	-$5.29	125%
ND	XTO	-$4.42	-1%
ND	ZAVANNA	-$7.11	64%
NM	CIMAREX	$1.22	25%
NM	CONOCO	$1.22	25%
NM	LEGACY RESERVE	$1.22	25%
NM	MARATHON	$1.22	25%
NM	RAYA	$1.22	25%
OK	CHESAPEAKE	$1.22	25%
TX	CML	-$3.42	-3%
TX	CONTANGO	-$2.50	0%
TX	NEWBRIDGE	-$3.00	-100%
TX	PIONEER	$1.22	25%
TX	WCS	-$2.46	-39%
WY	BASS	$1.22	25%

Proven Developed Oil and Gas reserves, as shown in the E-mailed reports, are reserves that geological and engineering data indicate to be recoverable from known oil and gas reservoirs through existing wells with existing operating methods.

The reserves and values included in this report are estimates only and should not be construed as being exact quantities. The reserve estimates were performed using accepted engineering practices and were primarily based on historical rate decline analysis for existing producers. As additional pressure and production performance data becomes available, reserve estimates may increase or decrease in the future. The revenue from such reserves and the actual costs related may be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the prices actually received for the reserves included in this report and the costs incurred in recovering such reserves may vary from the price and cost assumptions referenced. Therefore, in all cases, estimates of reserves may increase or decrease as a result of future operations.

In evaluating the information available for this analysis, items excluded from consideration were all matters as to which legal or accounting, rather than engineering interpretation, may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and such conclusions necessarily represent only informed professional judgments.

The title to the property has not been examined nor has the actual degree or type of interest owned been independently confirmed. A field inspection of the properties is not usually considered necessary for the purpose of this report.

Information included in this report includes the graphical decline curves, historical and projected production and cash flow economic results, and miscellaneous individual well information. Additional information reviewed will be retained and is available for review at any time. I can take no responsibility for the accuracy of the data used in the analysis, whether gathered from public sources or otherwise.

Reserve classifications conform to the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System (SPE-PRMS) which are available for review in a 49 page document at www.spee.org/images/PDFs/ReferencesResources/Petroleum_Resources_Management_System_2007.pdf. A 5 page abbreviated summary of the proved reserve classes is attached to the report.

Sincerely,

Don Jacks

STATE OF TEXAS
DONALD C. JACKS
73499
REGISTERED
PROFESSIONAL ENGINEER

Don Jacks, Texas Professional Engineer 73499