FORM 10-K

Annual report pursuant to section 13 and 15(d)

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ABRAXAS PETROLEUM CORP

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

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2021

☐ 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 001-16071

ABRAXAS PETROLEUM CORPORATION
(Exact name of Registrant as specified in its charter)

Nevada	**74-2584033**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification Number)

18803 Meisner Drive
San Antonio, TX 78258
(Address of principal executive offices)

(210) 490-4788
Registrant's telephone number, including area code

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class:	Trading Symbol	Name of each exchange on which registered:
Common Stock, par value $.01 per share	AXAS	OTCQX

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

None

Indicate by check mark if the registrant is a well-known seasoned issuer as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes ☐ No ☒

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

Indicate by check mark if 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 ☒ No ☐

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

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☐	Smaller reporting company ☒
	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 Exchange Act). Yes ☐ No ☒

As of June 30, 2021, the last day of the registrant’s most recently completed second fiscal quarter, the aggregate market value of the common stock held by non-affiliates of the registrant was $26,530,865 based on the closing sale price as reported on the OTCQX.

As of March 18, 2022, there were 8,421,910 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant’s Proxy Statement relating to the 2022 Annual Meeting of Stockholders to be held on May 11, 2022.	Part III

ABRAXAS PETROLEUM CORPORATION
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We make forward-looking statements throughout this report. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like “believe,” “expect,” “anticipate,” “intend,” “will,” “plan,” “seek,” “may,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looking statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this report is generally located in the material set forth under the headings “Business,” “Properties,” “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” but may be found in other locations as well. These forward-looking statements generally relate to our plans and objectives for future operations and are based upon our management’s reasonable estimates of future results or trends. The factors that may affect our expectations regarding our operations include, among others, the following:

- the prices we receive for our production and the effectiveness of our hedging activities, if any;
- the availability of capital including under any applicable credit facilities;
- our success in development, exploitation and exploration activities;
- declines in our production of oil and gas;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
- limits on our growth and our ability to finance our operations, fund our capital needs and respond to changing conditions;
- our ability to make planned capital expenditures;
- ceiling test write-downs resulting, and that could result in the future, from lower oil and gas prices;
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as the coronavirus (COVID-19);
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our ability to procure services and equipment for our drilling and completion activities;
- our acquisition and divestiture activities;
- weather conditions and events; and
- other factors discussed elsewhere in this report.

Initial production, or IP, rates, for both our wells and for those wells that are located near our properties, are limited data points in each well’s productive history. These rates are sometimes actual rates and sometimes extrapolated or normalized rates. As such, the rates for a particular well may change as additional data becomes available. Peak production rates are not necessarily indicative or predictive of future production rates, expected ultimate recovery, or EUR, or economic rates of return from such wells and should not be relied upon for such purposes. Equally, the way we calculate and report peak IP rates and the methodologies employed by others may not be consistent, and thus the values reported may not be directly and meaningfully comparable. Lateral lengths described are indicative only. Actual completed lateral lengths depend on various considerations such as lease-line offsets. Abraxas standard length laterals, sometimes referred to as 5,000 foot laterals, are laterals with completed length generally between 4,000 feet and 5,500 feet. Mid-length laterals, sometimes referred to as 7,500 foot laterals, are laterals with completed length generally between 6,500 feet and 8,000 feet. Long laterals, sometimes referred to as 10,000 foot laterals, are laterals with completed length generally longer than 8,000 feet.

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GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located at 60 degrees Fahrenheit. Oil and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil.

The following definitions shall apply to the technical terms used in this report.

<u>Terms used to describe quantities of oil and gas:</u>

"***Bbl***" – barrel or barrels.

"***Bcf***" – billion cubic feet of gas.

"***Bcfe***" – billion cubic feet of gas equivalent.

"***Boe***" – barrels of oil equivalent.

"***Boepd***" - barrels of oil equivalents per day.

"***MBbl***" – thousand barrels.

"MBoe" **–** thousand barrels of oil equivalent.

"***Mcf***" – thousand cubic feet of gas.

"***Mcfe***" – thousand cubic feet of gas equivalent.

"***MMBbl***" – million barrels.

"MMBoe" – million barrels of oil equivalent.

"***MMBtu***" – million British Thermal Units of gas.

"***MMcf***" – million cubic feet of gas.

"***MMcfe***" – million cubic feet of gas equivalent.

"NGL" **–** natural gas liquids measured in barrels.

<u>Terms used to describe our interests in wells and acreage:</u>

"***Developed acreage***" means acreage which consists of leased acres spaced or assignable to productive wells.

"***Development well***" is a well drilled within the proved area of an oil or gas reservoir to the depth or stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting reserves.

"***Dry hole***" is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion.

"***Exploratory well***" is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be producing in another reservoir, or to extend a known reservoir.

"***Gross acres***" are the number of acres in which we own a working interest.

"***Gross well***" is a well in which we own an interest.

"***Net acres***" are the sum of fractional ownership working interests in gross acres (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

"***Net well***" is the sum of fractional ownership working interests in gross wells.

"***Productive well***" is an exploratory or a development well that is not a dry hole.

"***Undeveloped acreage***" means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

"***Developed oil and gas reserves****" Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Proved developed non-producing reserves*" are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

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

"***Proved oil and gas reserves****" Reserves that 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" *or* ***"PUDs*"*** Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.

"***PV-10***" means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission ("SEC"). PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

"***Standardized Measure***" means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation or de-escalation, calculated in accordance with Accounting Standards Codification ("ASC") 932, "Disclosures About Oil and Gas Producing Activities."

"Undeveloped oil and gas reserves*" Undeveloped oil and gas reserves are reserves of any category 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.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition, see: http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=7aa25d3cede06103c0ecec861362497d&ty=HTML&h=L&n=pt17.3.210&r=PART#se17.3.210_14_610

Part I

Information contained in this report represents the consolidated operations of Abraxas Petroleum Corporation. The terms "Abraxas," "we," "us," "our," or the "Company," refer to Abraxas Petroleum Corporation, together with its consolidated subsidiaries including Raven Drilling, LLC which is a wholly owned subsidiary that owns a drilling rig. Unless otherwise noted, all disclosures are for Continuing Operations.

Item 1. Business

General

We are an independent energy company primarily engaged in the acquisition, exploration, development and production of oil and gas. At December 31, 2021, our estimated net proved reserves were 14.8 MMBoe, of which 100% were classified as proved developed, 46% were oil and 97% of which (on a Boe basis) were operated by us. Our daily net production for the year ended December 31, 2021 was 5,545 Boepd, of which 47% was oil. Abraxas Petroleum Corporation was incorporated in Nevada in 1990. Our address is 18803 Meisner Drive, San Antonio, Texas 78258 and our phone number is (210) 490-4788.

COVID-19 Overview

In the first quarter of 2020, a new strain of coronavirus ("COVID-19") emerged, creating a global health emergency that has been classified by the World Health Organization as a pandemic. As a result of the COVID-19 pandemic, consumer demand for both oil and gas decreased as a direct result of travel restrictions placed by governments in an effort to curtail the spread of COVID-19 and its variants. In addition, in March 2020, members of Organization of Petroleum Exporting Countries ("OPEC") failed to agree on production levels, which caused an increased supply of oil and gas and led to a substantial decrease in oil prices and an increasingly volatile market. OPEC agreed to cut global petroleum output but did not go far enough to offset the impact of COVID-19 on demand. As a result of this decrease in demand and increase in supply, the price of oil and gas decreased, which has affected our liquidity. Since that time, demand and the price of oil and gas have increased, but uncertainty related to the pandemic caused by COVID-19 and its variant strains persists.

In early March 2020, global oil and natural gas prices declined sharply, rising in recent months, especially in connection with the war in Ukraine, but may decline again. The full impact of COVID-19 and its variants continues to evolve as of the date of this report. As such, it is uncertain as to the full magnitude that will have on the Company. Management is actively monitoring the global situation and the impact on the Company's future operations, financial position and liquidity in fiscal year 2022.

Our oil and gas assets were located in two operating regions, the Permian/Delaware Basin, and the Rocky Mountain as of December 31, 2021. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2021:

	Gross Producing Wells	Average Working Interest	Total Net Acres	Estimated Net Proved Reserves at December 31, 2021 (3)		Net Production for the Year Ended December 31, 2021	
				(Mboe)	% Oil	(Mboe)	% Oil
Permian/Delaware Basin (1)	105	79.84%	24,438	8,813	45%	874	57%
Rocky Mountain (2) (4)	73	59.22%	5,668	6,010	49%	1,150	40%
Total United States	178	71.40%	30,106	14,823	62%	2,024	47%

(1) Our properties in the Permian/Delaware Basin region are primarily located in Ward and Winkler Counties, Texas and produce oil and gas primarily from the Bone Spring and Wolfcamp formations.
(2) Our properties in the Rocky Mountain region are primarily located in the Williston Basin of North Dakota and Montana. In this region, our wells produce oil and gas from various reservoirs, primarily the Bakken, Three Forks and Red River formations.
(3) Net proved reserves excludes proved undeveloped reserves due to the Company's inability to fund the drilling and completion activities within the next five years.
(4) All of our Rocky Mountain properties were sold on January 3, 2022. See Note 14 "Subsequent Events."

Strategy and Recent Activity

Our business strategy is to focus our capital and resources on our core operated basins, improve financial flexibility and profitably grow production and reserves. Key elements of our business strategy include:

Focus our capital and resources on our core operated basins. During 2021, our core basins consisted of the Permian/Delaware Basin (Bone Spring and Wolfcamp) and Williston Basin (Bakken and Three Forks). In connection with the restructuring that occurred on January 3, 2022, our Williston Basin assets were sold. See Note 14 "Subsequent Events." Given the disparity which has existed during the past several years and which continues currently between oil and gas prices, the economics of drilling oil wells is far superior to drilling gas wells. Due to declines in oil prices, during the first half of 2020, we suspended our planned capital expenditures for 2020. This suspension of our capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources including under any credit facilities, the results of our exploitation efforts, our financial results and our ability to obtain permits for drilling locations. Due to the capital spending constraints imposed by our then-existing credit facilities, we did not adopt a 2021 drilling budget. As part of our efforts to focus our property portfolio, we also seek to sell assets we have deemed non-core. These include assets with a low working interest that are non-operated and/or that fall outside of our core basins. Any proceeds from these asset sales were used to reduce our indebtedness and/or be redeployed into our core operating basins.

Financial flexibility. Our primary source of capital is cash flows from operations. As of December 31, 2021, we had $71.4 million outstanding on our Third Amended and Restated First Lien Credit Facility, dated June 11, 2014 (as amended, modified, or supplemented, the "First Lien Credit Facility"), by and among the Company, the financial institutions party thereto as lenders, Société Générale, as "Issuing Lender" and administrative agent, with no availability, and $134.9 million under the $100,000,000 Term Loan Credit Agreement, dated November 13, 2019 (as amended, modified, or supplemented, the "Second Lien Credit Facility"), by and among the Company, the financial institutions party thereto as lenders, and Angelo Gordon Energy Servicer, LLC, as administrative agent, and we generated approximately $32.4 million of cash flows from operations for the year ended December 31, 2021. Additionally, any excess cash, as defined in the First Lien Credit Facility, was used to reduce the balance and simultaneously reduce the borrowing base to the then-new outstanding balance. In connection with the restructuring that was completed on January 3, 2022 our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

We have also sold producing properties from time to time in order to provide us with financial flexibility. In January 2019, we announced that we had engaged Petrie Partners to assist us in identifying and assessing our options for our Bakken properties. In October 2019, we announced that we had broadened the engagement of Petrie Partners to include a more thorough review of our business and strategic plans, competitive positioning and potential alternative transactions that might further enhance shareholder value. Petrie's expanded mandate to assess our options was a broad one, which included potential sales of assets, merger or acquisition transactions, additional financing alternatives or other strategic transactions. We closed on the sale of our Bakken properties on January 3, 2022. See Note 14 "Subsequent Events."

Profitably grow production and reserves. We have a substantial low-decline legacy production base as evidenced by our approximate 21-year average reserve life as of year-end 2021. Our capital would be deployed largely into unconventional oil assets with relatively predictable production profiles, yet steep initial decline rates. Therefore, the economics of these oil wells are highly dependent on both near term commodity prices and strong operational cost control. Cost savings achieved through efficiencies of using our own rig in the Williston Basin, and heightened focus on cost control in all of our operated positions both contributed to our historical success in adding low-cost barrels to our production base.

Further Recent Activity

Pursuant to the Exchange Agreement, dated as of January 3, 2022, between the Company and AG Energy Funding, LLC ("AGEF") and certain other agreements entered into by the Company on January 3, 2022, the Company, we effectuated a restructuring of the Company's then-existing indebtedness through a multi-part interdependent de levering transaction consisting of: (i) an Asset Purchase and Sale Agreement pursuant to which the Company sold to Lime Rock Resources V-A, L.P. certain oil, gas, and mineral properties in the Williston Basin region of North Dakota and other related assets belonging to the Company and its subsidiaries for $87,200,000 in cash ($73.3 million after customary closing adjustments), (the "Sale"), (ii) the pay down of the indebtedness and other obligations of the Company Abraxas and its subsidiaries under the First Lien Credit Facility and administrative agent and certain specified secured hedges from the proceeds of the Sale and, to the extent necessary, other cash of the Company; and (iii), a debt for equity exchange of the indebtedness and other obligations of the Company Abraxas and its subsidiaries under the $100,000,000 Second Lien Credit Facility, and all related loan and security documents (the "Exchange" and, together with the transactions referred to in clauses (i) and (ii), the "Restructuring"). See Note 14 "Subsequent Events."

AGEF was issued 685,505 shares of Series A Preferred Stock of the Company in the Exchange. The Series A Preferred Stock has the terms set forth in the Company's filed Preferred Stock Certificate of Designation (the "Certificate). Pursuant to the Certificate, any proceeds distributed to the Company's stockholders or otherwise received in respect of the capital stock of the Company in a merger or other liquidity event will be allocated among the Series A Preferred Stock and the Company's common stock as follows: (1) first, 100% to the Series A Preferred Stock until the Series A Preferred Stock has received $100 million of proceeds in the aggregate (the "Tier One Preference Amount"), (2) second, 95% to the Series A Preferred Stock and 5% to the Company's common stock until the Series A Preferred Stock has received $137.1 million, plus a 6.0% annual rate of return thereon from the date hereof; (3) thereafter, 75% to the Series A Preferred Stock and 25% to the Company's common stock. The Exchange Agreement entered into in connection with the Restructuring also provides for the potential funding by AGEF of an additional amount up to $12.0 million, if agreed to by AGEF and the disinterested members of the Company's Board of Directors. Any such additional amount funded would result in an increase to the Tier One Preference Amount equal to 1.5 x the amount of such additional funding. The shares of Series A Preferred Stock vote together as a single class with the Company's common stock, and each share of Series A Preferred Stock entitles the holder thereof to 69 votes. Accordingly, AGEF's ownership of the Series A Preferred Stock entitle it to approximately 85% of the voting power of the Company's current outstanding capital stock.

Todd Dittmann, Damon Putman and Daniel Baddeloo, each of whom are employees of AGEF were appointed to Abraxas' Board of Directors.

2022 Budget and Drilling Activities

Due to the capital spending constraints, we have not adopted a drilling budget for 2022. As discussed under Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*, during 2021 our level of indebtedness and the then existing commodity price environment presented challenges to our ability to comply with certain covenants in our then-existing credit facilities and under applicable auditing standards the independent accountants'' opinion on our financial statements for the year ended December 31, 2020 contains an explanatory paragraph regarding the Company's ability to continue as a "going concern". Due to the Company's continued lack of adequate capital do develop its proved undeveloped reserves, as of December 31, 2021, those reserves were written-off for financial reporting purposes. If and when the Company has adequate capital resources to fund the projects the reserves will be reinstated.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices we receive for our oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the world wide economy (particularly the manufacturing sector), foreign imports, political conditions in other petroleum producing countries, the actions of OPEC, domestic regulation, legislation and policies, and the outbreak of pandemic or contagious diseases, such as the recent COVID-19 coronavirus. Decreases in the prices we receive for our oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, our revenue, profitability and cash flow from operations. Refer to "Risk Factors – Risks Related to Our Industry — Market conditions for oil and gas and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows from operations, profitability and growth" and "Management's Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies" for more information relating to the effects that decreases in oil and gas prices have on us. To help mitigate the impact of commodity price volatility, we have at times hedged a portion of our production through the use of fixed price swaps and basis differential swap contracts. See "Management's Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Hedging Arrangements" and Note 11 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2021, four purchasers of production accounted for approximately 83% of our oil and gas sales. During the year ended December 31, 2020, four purchasers of production accounted for approximately 73% of our oil and gas sales. We believe that there are numerous other purchasers available to buy our oil and gas and that the loss of any of these purchasers would not materially affect our ability to sell our oil and gas. Furthermore, the largest purchasers of our oil and gas have changed from year to year.

Regulation of Oil and Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our properties are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by industry specific price controls, taxes, conservation, safety, environmental and other laws relating to the petroleum industry, and by changes in such laws and by periodically changing administrative regulations.

Federal, state and local laws and regulations govern oil and gas activities. Operators of oil and gas properties are required to have a number of permits in order to operate such properties, including operator permits and permits to dispose of salt water. In addition, under federal law, operators of oil and gas properties are required to possess certain certificates and permits in order to operate such properties. We possess all material requisite permits required by Federal, state and other local authorities in which we operate properties.

Development and Production

The operations of our properties are subject to various types of regulation at the federal, state and local levels. These types of regulations include requiring the operator of oil and gas properties to possess permits for the drilling and development of wells, post bonds in connection with various types of activities, and file reports concerning operations. Most states, and some counties and municipalities in which we operate, regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the flaring of gas;
- the method of completing and fracture stimulating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

Some states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some states allow forced pooling or unitization of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which our wells can be drilled. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, gas and NGLs within its jurisdiction.

Operations on Federal or Indian oil and gas leases must comply with numerous regulatory restrictions, including various non-discrimination statutes, and certain of such operations must be conducted pursuant to certain on-site security regulations and other permits issued by various tribal and federal agencies, including the Bureau of Land Management and the Office of Natural Resources Revenue, which we refer to as ONRR, (formerly Minerals Management Service). ONRR establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by ONRR and the state regulatory authorities is generally applicable to all federal and state oil and gas leases. Accordingly, we believe that the impact of royalty regulation on the operations of our properties should generally be the same as the impact on our competitors. We believe that the operations of our properties are in material compliance with all applicable regulations as they pertain to Federal or Indian oil and gas leases.

The failure to comply with these rules and regulations can result in substantial penalties, including lease suspension or termination in certain cases. The regulatory burden on the oil and gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect us.

Regulation of Transportation and Sale of Gas in the United States

Historically, the transportation and sale for resale of gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended, which we refer to as NGA, the Natural Gas Policy Act of 1978, as amended, which we refer to as NGPA, and regulations promulgated thereunder by the Federal Energy Regulatory Commission, which we refer to as FERC, and its predecessors. In the past, the federal government has regulated the prices at which gas could be sold. Deregulation of wellhead gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended, which we refer to as the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of gas effective January 1, 1993. While sales by producers of gas can currently be made at unregulated market prices, Congress could reenact price controls in the future.

Since 1985, FERC has endeavored to make gas transportation more accessible to gas buyers and sellers on an open and non-discriminatory basis. FERC has stated that open access policies are necessary to improve the competitive structure of the interstate gas pipeline industry and to create a regulatory framework that will put gas sellers into more direct contractual relations with gas buyers by, among other things, unbundling the sale of gas from the sale of transportation and storage services. Beginning in 1992, FERC issued Order No. 636 and a series of related orders, which we refer to collectively as Order No. 636, to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of gas have been significantly altered. The interstate pipelines' traditional role as wholesalers of gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell gas. FERC continues to regulate the rates that interstate pipelines may charge for such transportation and storage services. Although FERC's orders do not directly regulate gas producers, they are intended to foster increased competition within all phases of the gas industry.

In 2000, FERC issued Order No. 637 and subsequent orders, which we refer to, collectively, as Order No. 637, which imposed a number of additional reforms designed to enhance competition in gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 have been upheld on judicial review, and most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

The Energy Policy Act of 2005, which we refer to as EP Act 2005, gave FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended the NGA to prohibit market manipulation and also amended the NGA and the NGPA to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of

FERC to up to $1,000,000 per day, per violation. In addition, FERC issued a final rule effective January 26, 2006, regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of gas or transportation service subject to FERC jurisdiction, to defraud, make an untrue statement, or omit a material fact or engage in any practice, act, or course of business that operates or would operate as a fraud. This final rule works together with FERC's enhanced penalty authority to provide increased oversight of the gas marketplace.

The gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach currently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other gas producers, gatherers and marketers.

Generally, intrastate gas transportation is subject to regulation by state regulatory agencies, although FERC does regulate the rates, terms, and conditions of service provided by intrastate pipelines that transport gas subject to FERC's NGA jurisdiction pursuant to Section 311 of the NGPA. The basis for state regulation of intrastate gas transportation and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate gas transportation in any states in which we operate and ship gas on an intrastate basis will not affect the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

Gas Gathering in the United States

Section 1(b) of the NGA exempts gas gathering facilities from the jurisdiction of the FERC. FERC has developed tests for determining which facilities constitute jurisdictional transportation facilities under the NGA and which facilities constitute gathering facilities exempt from FERC's NGA jurisdiction. From time to time, FERC reconsiders its test for defining non-jurisdictional gathering. FERC has also permitted jurisdictional pipelines to "spin down" exempt gathering facilities into affiliated entities that are not subject to FERC jurisdiction, although FERC continues to examine the circumstances in which such a "spin down" is appropriate and whether it should reassert jurisdiction over certain gathering companies and facilities that previously had been "spun down." We cannot predict the effect that FERC's activities in this regard may have on the operations of our properties, but we do not expect these activities to affect the operations in any way that is materially different from the effect thereof on our competitors.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take or service requirements, but does not generally entail rate regulation. In the United States, gas gathering has received greater regulatory scrutiny at both the state and federal levels in the wake of the interstate pipeline restructuring under FERC Order 636. For example, the Texas Railroad Commission enacted a Natural Gas Transportation Standards and Code of Conduct to provide regulatory support for the state's more active review of rates, services and practices associated with the gathering and transportation of gas by an entity that provides such services to others for a fee, in order to prohibit such entities from unduly discriminating in favor of their affiliates.

Regulation of Transportation of Oil in the United States

Sales of oil, condensate and gas liquids are not currently regulated and are made at negotiated prices. The transportation of oil in common carrier pipelines is subject to rate regulation. 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, FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, FERC, in February 2003, increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulations, 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 the operations of our properties in any way that is materially different from the effect of such regulation on our competitors.

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 shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing 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 competitors.

All of our oil is sold on lease, at which time custody transfers, either by truck or pipeline. We are not able to determine how much of our sold oil is ultimately shipped to market centers using rail transportation facilities owned and operated by third parties. The U.S. Department of Transportation's ("U.S. DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") establishes safety regulations relating to transportation of oil by rail transportation. In addition, third party rail operators are subject to the regulatory jurisdiction of the Surface Transportation Board of the U.S. DOT, the Federal Railroad Administration ("FRA") of the DOT, the U.S. Occupational Safety and Health Administration, as well as other federal regulatory agencies. Additionally, various state and local agencies have jurisdiction over disposal of hazardous waste and seek to regulate movement of hazardous materials in ways not preempted by federal law.

In response to rail accidents occurring between 2002 and 2008, the U.S. Congress passed the Rail Safety and Improvement Act of 2008, which implemented regulations governing different areas related to railroad safety. Recently, in response to train derailments occurring in 2013, U.S. regulators have been implementing or considering new rules to address the safety risks of transporting oil by rail. On January 23, 2014, the National Transportation Safety Board ("NTSB") issued a series of recommendations to the FRA and PHMSA to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) developing an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) auditing shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the DOT issued an emergency order requiring all persons, prior to offering oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of oil be handled as a Packing Group I or II hazardous material.

We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any regulations that impact the testing or handling of shipments of oil by rail transportation could increase our costs of doing business and limit our ability to transport and sell our oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows from operations. At this time, it is not possible to estimate the potential impact on our business if new federal or state rail transportation regulations are enacted.

Environmental Matters

Oil and gas operations are subject to numerous federal, state and local laws and regulations controlling the generation, use, treatment, storage and disposal of materials and the discharge of materials into the environment or otherwise relating to the protection of the environment. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences;
- impose design, construction and permitting requirements on facilities in conjunction with oil and gas operations, including the construction of pollution control devices;
- require protective measures to prevent certain fluids from coming into contact with ground water;
- restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production, and gas processing activities;
- suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands, and areas inhabited by threatened or endangered species and other protected areas;
- require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells;
- require disclosure of chemicals injected into wells in conjunction with hydraulic fracturing operations;
- restrict injection of liquids into subsurface strata that may contaminate groundwater or increase seismic activity;
- restrict the availability of water necessary for hydraulic fracturing operations;
- impose substantial penalties for violations of environmental rules or pollution resulting from our operations;
- curtail production in association with permit limits; and
- curtail or prohibit production for exceeding gas flaring limits.

Environmental permits that the operators of properties are required to possess may be subject to revocation, modification, and renewal by issuing authorities. Governmental authorities have the power to enforce compliance with their regulations and permits, and violations are subject to injunction, civil fines, and even criminal penalties. Our management believes that we are in substantial compliance with current environmental laws and regulations, and that we will not be required to make material capital expenditures to comply with existing laws. Nevertheless, changes in existing environmental laws and regulations or interpretations thereof could have a significant impact on our operations as well as the oil and gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

We are not currently involved in any administrative, judicial or legal proceedings arising under federal, state, or local environmental protection laws and regulations, or under federal or state common law, which would have a material adverse effect on our respective financial positions or results of operations. Moreover, we maintain insurance against the costs of clean-up operations, but we are not fully insured against all such risks. A serious incident of pollution may result in the suspension or cessation of operations in the affected area.

The following is a discussion of the current relevant environmental laws and regulations that relate to our operations.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, also known as Superfund, and which we refer to as "CERCLA", and comparable state statutes impose strict joint, and several liability, without regard to fault or legality of conduct, on certain classes of persons who are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include among others, the current and former owners or operators of a disposal site or sites where a release occurred and companies that arranged for the transportation or disposal of the hazardous substances released at the site. Under CERCLA, such persons or companies may be retroactively liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA authorizes the Environmental Protection Agency("EPA"), 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. In addition, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage, and recovery of response costs allegedly caused by the hazardous substances released into the environment.

In the course of our ordinary operations, certain wastes may be generated that may fall within CERCLA's definition of a "hazardous substance." We may be liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. Although CERCLA contains a "petroleum exclusion" from the definition of "hazardous substance," state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including oil cleanups.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we have utilized standard industry operating and disposal practices at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties we owned or leased or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, RCRA (as defined below), and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators; to clean up contaminated property, including contaminated groundwater; or to perform remedial operations to prevent future contamination.

Oil Pollution Act of 1990. 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 Federal Oil Pollution Act, which we refer to as 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. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility and other operating requirements will not have a material adverse effect on our financial position or results of operations.

Resource Conservation and Recovery Act. The Resource Conservation and Recovery Act, which we refer to as "RCRA", is the principal federal statute governing the treatment, storage and disposal of hazardous and non-hazardous solid wastes. RCRA imposes stringent requirements and liability for failure to meet such requirements, on persons who generate or transport regulated waste materials and also on persons who own or operate a waste treatment, storage or disposal facility. Analogous state laws also impose requirements associated with the management such wastes. At present, RCRA includes a statutory exemption that allows most oil and gas exploration and production wastes to be classified and regulated as non-hazardous wastes. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and gas exploration and production wastes from regulation as hazardous wastes. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose and would cause us to incur increased operating expenses. Also, in the ordinary course of our operations, we generate small amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes. We believe that our operations comply in all material respects with the requirements of RCRA and its state counterparts.

Naturally Occurring Radioactive Materials, which we refer to as "NORM", are materials not covered by the Atomic Energy Act, whose radioactivity is enhanced by technological operations such as mineral extraction or processing through exploration and production conducted by the oil and gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection; treatment, storage and disposal of NORM waste; management of waste piles, containers and tanks; and limitations upon the release of NORM contaminated land for unrestricted use. We believe that the operations of our properties are in material compliance with all applicable NORM standards established by the various states in which we operate wells.

Clean Water Act. The Clean Water Act, which we refer to as the "CWA", and analogous state laws, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The CWA regulates storm water run-off from oil and gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. 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 resource damages resulting from the release. We believe that the operations of our properties comply in all material respects with the requirements of the CWA and state statutes enacted to control water pollution.

Safe Drinking Water Act. Our operations also produce wastewaters that are disposed via underground injection wells. These activities are regulated by the Safe Drinking Water Act, which we refer to as the "SDWA", and analogous state and local laws. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and gas production., or the flow-back of hydraulic fracturing fluids. The main goal of the SDWA is the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In most states, no underground injection may take place except as authorized by permit or rule. In addition, subsurface injection of water or other produced fluids from drilling or hydraulic fracturing processes have come under increased public and governmental scrutiny. Some jurisdictions, Texas for example, have adopted new and more stringent rules for injection wells aimed at reducing the potential for earthquakes associated with injection activities, including new restrictions on siting of such injection wells. We currently own and operate various underground injection wells and rely on third-party owned injection wells. Failure to comply with our permits could subject us to civil and/or criminal enforcement. More stringent regulations of injection wells could additionally increase our cost of operations. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Clean Air Act. The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operation of our properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. In the past few years, EPA has adopted new more restrictive regulations governing air emissions from oil and gas operations, including regulations which restrict emissions of methane, volatile organic compounds and hazardous air pollutants.

Permits and related compliance obligations under the CAA, as well as changes to state implementation plans for controlling air emissions in regional non-attainment areas may require us to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies. In addition, some oil and gas facilities may be included within the categories of hazardous air pollutant sources, which are subject to more stringent regulation under the CAA. Failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and enforcement actions. We may be required to incur capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe that we are in compliance in all material respects with the requirements of applicable federal and state air pollution control laws.

Hydraulic Fracturing. Most of our current operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand, or other proppants, into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our newer wells would not be economical without the use of hydraulic fracturing to stimulate the formation to enhance production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and 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"). 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, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in hydraulic fracturing, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact the availability of water for hydraulic fracturing. If these types of restrictions are widely adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells, and these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with water wells in the vicinity of an oil or gas well or other alleged environmental problems. Additional information concerning hydraulic fracturing is included under Item 1A "Risk Factors."

Climate Change and Greenhouse Gas Regulation. Scientific studies have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" or "GHGs" pursuant to efforts spearheaded by the United Nations. Reports from numerous global and domestic governmental agencies tasked with researching, evaluating, and mitigating the impact of climate change, such as the Sixth Assessment Report of the United Nations Intergovernmental Panel on Climate Change, released in part in August 2021 and February 2022 with a full release expected in September 2022, and, the Fourth National Climate Assessment report of the U.S. Global Change Research Program, released in full in November 2018, have pointed to GHG emissions as the main driver of atmospheric warming and that climate change is accelerating. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered GHGs. We expect continuing debate, especially in the political arena, over how to address climate change and what policies and regulations are necessary to address the issue. It is possible that domestic and international regulations addressing climate change will have adverse effects on the market for oil, gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, oil, gas and other fossil fuel products. Given widely divergent political views on climate change regulation, we are unable to predict the timing, scope and effect of any proposed or future legislation, investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such measures (if enacted) could materially and adversely affect our operations, financial condition and results of operations. In addition, several states and local governments have adopted, or are considering adopting, regulations or ordinances to reduce emissions of GHGs. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. The various efforts to regulate the emissions of GHGs (including lawsuits pending in United States federal courts) may affect the cost of our operations, may affect the public's perception of our industry, and may reduce demand for our products.

An example of the uncertainty in regulations comes from the BLM flaring rule. In November 2016, BLM issued a final rule to further restrict venting and flaring of gas from oil and gas operations on public lands. Then, BLM issued a stay of these requirements in December 2017. In September 2018, BLM published a final rule to modify and rescind substantial portions of the flaring rule. The rescission was challenged by litigation filed in the U.S. District Court for the Northern District of California. In July 2020, the California federal court vacated the revised rule, focusing on the rulemaking process and not the content of rule itself. That court stayed its vacatur of the revised rule until October 13, 2020, however, to give the parties in a similar Wyoming litigation time to move forward in their proceedings regarding the 2016 Rule. Shortly thereafter, the Wyoming federal district court struck down the rule, however, the fight over methane emission regulation remains heated. If any laws restricting flaring of gas become effective, we would have to curtail production from the affected wells and would incur additional costs of compliance as well as increased monitoring and recordkeeping for some of our facilities.

Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations. Additional information concerning climate change is included under Item 1A. "Risk Factors."

National Environmental Policy Act. Oil and gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, which we refer to as NEPA. NEPA requires federal agencies, including the Department of the Interior, 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 the development of oil and gas projects and increase the cost of such operations.

Endangered Species Act. The Endangered Species Act, which we refer to as the ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our properties may be located in areas that may be designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. Looking forward, we expect more listings of such species to occur, in light of renewed efforts by certain environmental activists to use the ESA as a mechanism to restrict land development and energy production. Such listings could include habitat in areas where we operate or plan to operate, or which could adversely affect our ability to secure needed sand, water or other materials for our operations or to transport oil or gas via pipeline to our customers. Further, some of the species could become subject to voluntary rangeland conservation plans that could affect our operations of sources of materials. Such listing of additional species, or the discovery of previously unidentified endangered or threatened species, or the adoption of conservation plans, could cause us to incur additional costs or become subject to operating restrictions, construction delays, or bans on operating in the affected areas.

Abandonment Costs. All of our oil and gas wells will require proper plugging and abandonment at some time in the future. We have posted bonds with most regulatory agencies to ensure compliance with our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

Title to Properties

As is customary in the oil and gas industry, we make only a cursory review of title to undeveloped oil and gas leases at the time we acquire them. However, before drilling commences, we make a thorough title search, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller/lessor of the undeveloped property, are typically obligated to cure any title defect at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our properties, some of which are subject to immaterial encumbrances, easements and restrictions. The oil and gas properties we own are also typically subject to royalty and other similar non-cost bearing interests customary in the industry. We do not believe that any of these encumbrances or burdens will materially affect our ownership or use of our properties.

Competition

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment and services to explore for such reserves and knowledgeable personnel to conduct all phases of oil and gas operations. We must compete for such resources with both major oil and gas companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our near-term operations, we cannot assure you that such materials and resources will be available to us in the future.

Employees

As of March 18, 2022, we had 42 full-time employees. We retain independent geological, land, marketing, engineering and health and safety consultants from time to time and expect to continue to do so in the future. We operate on the fundamental philosophy that people are our most valuable asset as every person who works for us has the potential to impact our success. Identifying quality talent is at the core of everything we do and our success is dependent upon our ability to attract, develop and retain highly qualified employees. Our core values include honesty/integrity, treating people fairly, high performance, efficient and effective processes, open communication and being respected in our local communities. These values establish the foundation on which the culture is built and represent the key expectations we have of our employees. We believe our culture and commitment to our employees creates an environment that allows us to attract and retain our qualified talent, while simultaneously providing significant value to the Company and its stockholders by helping our employees attain their highest level of creativity and efficiency.

Available Information

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). You may read and copy any document we file with the SEC at the SEC's public reference room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for information on the public reference room. The SEC maintains an internet web site that contains annual, quarterly and current reports, proxy statements and other information that issuers (including Abraxas) file electronically with the SEC. The SEC's web site is www.sec.gov.

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments filed with the SEC are available free of charge on our web site at www.abraxaspetroleum.com in the Investor Relations section as soon as practicable after such reports are filed. Information on our web site is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

Item 1A. Risk Factors

Risks Related to Our Business

Depressed oil and/or gas prices would have a material and adverse effect on us.

Our financial results and the value of our properties are highly dependent on the general supply and demand for oil, gas and NGL, which impact the prices we ultimately realize on our sales of these commodities. In addition to the impact on our results of operations, future declines in oil and gas prices could cause us to write down the value of our estimated proved reserves. Oil and natural gas prices remain volatile, and as a result, we could record impairments in future periods, the amount of which will be dependent upon many factors such as future prices of oil, gas and NGL, increases or decreases in our reserve base, changes in estimated costs and expenses, and oil and gas property acquisitions.

Prices in 2021 have improved from the sharp decline at the beginning of March 2020, and price volatility continued into 2021, improving in late 2021. Prices improved significantly in the first part of 2022, however future deterioration in commodity prices could materially and adversely impact our business by resulting in, or exacerbating, the following effects:

- reducing the amount of oil, gas and NGL that we can produce economically;
- limiting our financial flexibility, liquidity and access to sources of capital, such as equity and debt;
- reducing our revenues, cash flows from operations and profitability;
- causing us to decrease our capital expenditures or maintain reduced capital spending for an extended period, resulting in lower future production of oil, gas and NGL; and
- reducing the carrying value of our properties, resulting in additional noncash write-downs.

Market prices and our realized prices have been volatile and are likely to continue to be volatile in the future due to numerous factors beyond our control. These factors include:

- the level of demand;
- domestic and global supplies of oil, NGL and gas;
- the price and quantity of imported and exported oil, NGL and gas;
- the actions of other oil exporting nations;
- weather conditions and changes in weather patterns;
- the availability, proximity and capacity of appropriate transportation facilities, gathering, processing and compression facilities, storage facilities and refining facilities;
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as the coronavirus (COVID-19);
- worldwide economic and political conditions, including political instability or armed conflict in oil and gas producing regions, competition for markets and political initiatives disfavoring fossil fuels;
- the price and availability of, and demand for, competing energy sources, including alternative energy sources;
- the nature and extent of governmental regulation, including environmental regulation, regulation of derivatives transactions and hedging activities, tax laws and regulations and laws and regulations with respect to the import and export of oil, gas and related commodities;
- the level and effect of trading in commodity futures markets, including trading by commodity price speculators and others, and;
- the effect of worldwide energy conservation measures.

Our cash flows from operations depend to a great extent on the prevailing prices for oil and gas, as well as our hedges to offset declines in price. Prolonged or substantial declines in oil and/or gas prices would materially and adversely affect our liquidity, the amount of cash flows we have available for our capital expenditures and other operating expenses, our ability to access the credit and capital markets and our results of operations.

The marketability of our production depends largely upon the availability, proximity and capacity of oil and gas gathering systems, pipelines, storage and processing facilities.

The marketability of our production depends in part upon processing, storage and transportation facilities, which are also known as midstream facilities, owned and operated by third parties. Transportation space on such gathering systems and pipelines is limited and at times unavailable due to repairs or improvements being made to such facilities or due to such space being utilized by other companies with priority transportation agreements. Our access to transportation options can also be affected by federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If adequate transportation and storage options are not available to us, the financial impact on us could be substantial and adversely affect our ability to produce and market our oil and gas. For example, rapid production growth in the Permian Basin has strained the available midstream infrastructure there with adverse effects on our operations.

In addition to causing production curtailments and reducing the price we receive for the oil, gas and NGL we produce, given environmental impacts, including GHG production, regulatory agencies have adopted policies to reduce the volume of flared gas, the number of wells flaring, and the duration of flaring. While these regulations have not had a material adverse effect on us to date, these current regulations relating to flaring gas or the adoption of additional regulations could cause us to shut-in production or curtail the drilling of new wells either of which could have a material adverse effect on us.

We rely on third parties to continue to construct additional midstream facilities and related infrastructure to accommodate our growth, and the ability and willingness of those parties to do so is subject to a variety of risks.

For example:

- Decreases in commodity prices in recent years have resulted in reduced investment in midstream facilities by some third parties;
- Various interest groups have protested the construction of new pipelines, and particularly pipelines near water bodies, in various places throughout the country, and protests have at times physically interrupted pipeline construction activities; and
- Some companies in our industry have sought to reject volume commitment agreements with midstream providers in bankruptcy proceedings, and the risk that such efforts will succeed, or that upstream energy company counterparties will otherwise be unable or unwilling to satisfy their volume commitments, may have the effect of reducing investment in midstream infrastructure.

We have pursued a variety of strategies to alleviate some of the risks associated with the midstream services and facilities upon which we rely, including seeking alternative sources for processing and transporting gas that we produce. There can be no assurance that the strategies we pursue will be successful or adequate to meet our needs.

Lower oil and/or gas prices may also reduce the amount of oil and/or gas that we can produce economically.

Substantial declines in oil and/or gas prices may render uneconomic a significant portion of our exploration, development and exploitation projects, which may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a prolonged or substantial decline in oil and/or gas prices has historically caused, and would likely in the future cause, a material and adverse effect on our future business, financial condition, results of operations, liquidity and ability to finance capital expenditures. Additionally, if we experience significant sustained decreases in oil and gas prices such that the expected future cash flows from our oil and gas properties falls below the net book value of our properties, we may be required to write down the value of our oil and gas properties. Any such asset impairments could materially and adversely affect our results of operations and, in turn, the trading price of our common stock and ultimately affect our listing on any public market.

We may not be able to fund the capital expenditures that will be required for us to increase reserves and production.

We must make capital expenditures to develop our existing reserves and to discover new reserves. Historically, we have financed our capital expenditures primarily with cash flows from operations, borrowings under credit facilities, sales of properties, monetizing derivative contracts and sales of debt and equity securities and we expect to continue to utilize these sources in the future to the extent available. We cannot assure you that we will have sufficient capital resources in the future to finance all of our planned capital expenditures, additionally, any future credit facilities, could place restrictions on our capital expenditures.

Volatility in oil and gas prices, the timing of our drilling programs and drilling results will affect our cash flows from operations. Lower prices and/or lower production could also decrease revenues and cash flows from operations, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flows from operations does not increase as a result of capital expenditures, a greater percentage of our cash flows from operations will be required for any applicable debt service and operating expenses and our capital expenditures would, by necessity, be decreased.

If cash flows from operations or our borrowing base, if applicable, decrease, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited.

If we cannot replace the production from the properties sold with production from our remaining properties, our cash flows from operations will likely decrease, which in turn, could decrease the amount of cash available for additional capital spending.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

Our First Lien Credit Facility and our Second Lien Credit Facility contained a number of significant covenants that, among other things, limited our ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments, including repurchasing, redeeming or retiring capital stock or subordinated debt or making certain investments or acquisitions;
- engage in transactions with affiliates;
- make any change in the principal nature of our business;
- permit a change of control; or
- consolidate, merge or transfer all or substantially all of our assets.

In addition, our credit facilities required us to maintain compliance with specified financial covenants. Any future credit facilities we obtain could contain similar or even more restrictive covenants and our ability to comply with such covenants may be adversely affected by events beyond our control, and we cannot assure you that we would be able to maintain compliance with such covenants. These financial covenants could limit our ability pursuant to the credit agreements to obtain future advances, make needed capital expenditures or otherwise conduct necessary or desirable business activities. Even if new financing becomes available, it may not be on terms acceptable or favorable to us.

Lower oil and gas prices increase the risk of ceiling limitation write-downs.

We use the full cost method to account for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop our oil and gas properties. Under full cost accounting rules, the net capitalized cost of our oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from our proved reserves, discounted at 10%. If the net capitalized costs of our oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flows from operating activities, but it does reduce our stockholders' equity and earnings. The risk that we will be required to write-down the carrying value of our oil and gas properties increases when oil and gas prices are low, which could be further impacted by the SEC's oil and gas reporting disclosures, which require us to use an average price over the prior 12-month period, rather than the year-end price, when calculating the PV-10. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though oil and gas prices may have increased the ceiling applicable in the subsequent period.

At December 31, 2020, the net capitalized costs of our oil and gas properties exceeded the present value of estimated future cash flows from our proved reserves, resulting in recognition of an impairment of $187.0 million for the year ended December 31, 2020. At December 31, 2021 the net capitalized costs of our oil and gas properties did not exceed the present value of estimated future cash flows from our proved reserves.

An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flows from operations.

Our oil and gas are priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for our oil and gas are typically lower than the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as refinery capacity, location to market, product quality, pipeline capacity and specifications, upsets in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Additionally, insufficient pipeline capacity, lack of demand in any given operating area or other factors may cause the differential to increase in a particular area compared with other producing areas.

During 2021, our differentials averaged $ (4.13) per Bbl of oil and $ (1.21) per Mcf of gas. Approximately 48% of our oil production during 2021 was from the Rocky Mountain region and approximately 52% from the Permian region. Increases in the differential between the benchmark prices for oil and gas and the realized price we receive could significantly reduce our revenues and our cash flow from operations.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development and exploratory drilling activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. For example, the Company's proved reserves as of December 31, 2021 included proved developed reserves that are behind pipe of 308 MBbls of oil, 103 MBbls of NGL and 2,187 MMcf of gas. Due to the continued lack of adequate capital to develop its proved undeveloped reserves, those reserves were removed for 2020 and 2021. If and when the Company has the capital to complete the undeveloped reserves, they will be reinstated in the Company's total proved reserves. The Company's ability to drill and develop these locations depends on a number of factors, including the availability of capital, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. There can be no assurance that the Company will drill these locations or that the Company will be able to produce oil or gas reserves from these locations or any other potential drilling locations. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company's ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately result in the realization of proved reserves or meet the Company's expectations for success. As such, the Company's actual drilling activities may materially differ from the Company's current expectations, which could have a significant adverse effect on the Company's proved reserves, financial condition and results of operations.

We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced. Unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, we cannot assure you that our exploration and development activities will result in increases in our proved reserves. Based on the reserve information set forth in our reserve report as of December 31, 2021, our average annual estimated decline rate for our net proved developed producing reserves is 20%; 15% ; 13% ; 12% ;and 11% in 2022, 2023, 2024, 2025 and 2026, respectively, 9% in the following five years, and approximately 10% thereafter. These rates of decline are estimates and actual production declines could be materially higher. We have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. As our proved reserves and consequently our production decline, our cash flow from operations, and the amount that we are able to borrow under our credit facilities could also decline.

We may not find any commercially productive oil and gas reservoirs.

Drilling involves numerous risks, including the risk that the new wells we drill will be unproductive or that we will not recover all or any portion of our capital investment. Drilling for oil and gas may be unprofitable. Wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling and completion operations. Due to the lack of adequate capital to develop its proved undeveloped reserves, such reserves have been removed for 2020 and 2021. If the volume of oil and gas we produce decreases, our cash flows from operations may decrease.

The results of our drilling in unconventional formations, principally in emerging plays with limited drilling and production history using long laterals and modern completion techniques, are subject to more uncertainties than our drilling program in the more established plays and may not meet our expectations for reserves or production.

We drill wells in unconventional formations in several emerging plays. Part of our drilling strategy to maximize recoveries from these formations involves the drilling of long horizontal laterals and the use of modern completion techniques of multi-stage fracture stimulations that have proven to be successful in other basins. Risks that we face include landing our well bore in the desired drilling zone, staying in the desired drilling zone, running casing the entire length of the well bore and being able to run tools and recover equipment the entire length of the well bore during completion. Our experience with horizontal drilling and multi-stage fracture stimulations of these formations to date, as well as the industry's drilling and production history in these formations, is relatively limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and longer term production profiles are established. In addition, based on reported decline rates in these emerging plays as well as the industry's experience in these formations, we estimate that the average monthly rates of production may decline as much as 95% during the first twelve months of production. Actual decline rates may differ significantly. Accordingly, the results of our drilling in these unconventional formations are more uncertain than drilling results in other more established plays with longer reserve and production histories.

We may not be able to keep pace with technological developments in our industry.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other oil and gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

We may not adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- prevailing and anticipated prices for oil and gas;
- the availability and costs of drilling and service equipment and crews;
- economic and industry conditions at the time of drilling;
- the availability of sufficient capital resources;
- the results of our exploitation efforts;
- the acquisition, review and interpretation of seismic data;
- our ability to obtain permits for and to access drilling locations;
- continuous drilling obligations; and
- lease expirations.

Although we have identified numerous drilling locations, we may not be able to drill those locations within our expected time frame or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties. For example, we have in the past, and may be required in the future, to delay drilling or completing wells in order to protect them from fracture stimulation of other wells in the same area.

We cannot control the activities on the properties we do not operate and are unable to ensure their proper operation and profitability.

We currently do not operate all of the properties in which we have an interest. Non-operated properties represented approximately 3.8% of our estimated net proved reserves on a Boe basis at December 31, 2021. As a result, we have limited ability to exercise influence over and control the risks associated with operation of these properties. The failure of an operator to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including:

- the operator could refuse to initiate exploitation or development projects and if we proceed with any of those projects, we may not receive any funding from the operator with respect to that project;
- the operator may initiate exploitation or development projects on a different schedule than we would prefer;
- the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects and thus, not participate in the associated revenue stream; and
- the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploitation and development activities.

Weather conditions and other factors could adversely affect our ability to conduct drilling activities.

Our operations could be adversely affected by weather conditions and wildlife restrictions on federal leases. Severe weather conditions limit and may temporarily halt the ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our oil and gas operations and materially increase our operating and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

The lack of availability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploitation and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there has been a shortage of drilling rigs, equipment, supplies, oil field services or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. During times and in areas of increased activity, the demand for oilfield services will also likely rise, and the costs of these services will likely increase, while the quality of these services may suffer. If the lack of availability or high cost of drilling rigs, equipment, supplies, oil field services or qualified personnel were particularly severe in any of our areas of operation, we could be materially and adversely affected. Delays could also have an adverse effect on our results of operations, including the timing of the initiation of production from new wells.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors that are beyond our control.

Our drilling operations are subject to a number of risks, including:

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- adverse weather conditions;
- title problems;
- delays due to protection from fracture stimulations of nearby wells,
- unusual or unexpected geological formations;
- fires, blowouts and explosions; and
- uncontrollable pressures or flows of oil or gas or well fluids.

Any of these events could adversely affect our ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension of operations, and attorney's fees and other expenses incurred in the prosecution or defense of litigation.

We do not insure against all potential operating risks. We might incur substantial losses from, and be subject to substantial liability claims for, uninsured or underinsured risks related to our oil and gas operations.

We do not insure against all risks. Our oil and gas exploitation and production activities are subject to hazards and risks associated with drilling for, producing and transporting oil and gas, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of oil, gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, underground migration and surface spills or mishandling of chemical additives;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- leaks of gas, oil, condensate, NGL and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, or in the gathering and transportation of hydrocarbons, malfunctions of pipelines, measurement equipment or processing or other facilities in the Company's operations or at delivery points to third parties;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

We might elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations.

Hydraulic fracturing, the process used for extracting oil and gas from shale and other formations, could be the subject of further regulation that could impact the timing and cost of development.

Hydraulic fracturing is the primary completion method used to extract reserves located in many of the unconventional oil and gas plays. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure, usually down tubing or casing that is cemented in the wellbore, into hydrocarbon-bearing formations at depth to stimulate oil and gas production. We use this completion technique on substantially all of our wells. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal and state levels, exploration, exploitation and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements. Some states, including Texas, have implemented disclosure requirements related to chemicals used in hydraulic fracturing, and while the BLM has rescinded its rules governing hydraulic fracturing on federal and tribal lands (which action itself is subject to pending litigation), we anticipate further regulation of hydraulic fracturing and related activities by states and local governments. Individually or collectively, such existing and new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional oil and gas resources from formations which are not commercial without the use of hydraulic fracturing. This could have an adverse effect on our business, financial condition and results of operations.

Hydraulic fracturing is typically regulated by state oil and gas commissions; however, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Underground Injection Control Program established under the Safe Drinking Water Act, or SDWA, and published permitting guidance and an interpretive memorandum addressing the performance of such activities. In addition, the U.S. Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new federal level of legal restrictions relating to the hydraulic fracturing process is adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development or production activities.

Some states, including Texas, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosures, and/or well-construction requirements on hydraulic-fracturing operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. In some states, including Texas, water use may also be regulated and potentially curtailed by local groundwater management districts which could impact water available for hydraulic fracturing. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, in the event state or local 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 perhaps be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves.

See “Item 1. Business – Environmental Matters – Hydraulic Fracturing” above for additional discussion related to environmental risks associated with our hydraulic fracturing activities.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows from operations.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners and other sources for use in our operations. Over the past few years, extreme drought conditions persisted in West and South Texas. Although conditions have improved, we cannot guarantee what conditions may occur in the future. Severe drought conditions can result in local water districts taking steps to restrict the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local resources, we may be unable to economically produce oil and gas, which could have an adverse effect on our financial condition, results of operations and cash flows from operations.

Studies noting a connection between increased seismic activity and the injection of wastewater from oil and gas operations could result in new laws or regulations which would increase our cost of operations.

Some studies have noted an increase in localized frequency of seismic activity associated with underground injection wastewater from oil and gas operations. If the results of these studies are confirmed, new legislative and regulatory initiatives could require additional monitoring, restrict the injection of produced water in certain disposal wells or modify or curtail hydraulic fracturing operations. These actions could lead to operational delays, increased compliance costs or otherwise adversely impact our operations.

We face various risks associated with the trend toward increased anti-development activity.

As new technologies have been applied to our industry, we have seen significant growth in oil and gas supply in recent years, particularly in the U.S. With this expansion of oil and gas development activity, opposition toward oil and gas drilling and development activity has been growing both in the U.S. and globally. Companies in the oil and gas industry, such as us, can be the target of opposition to development from certain stakeholder groups. These anti-development efforts could be focused on:

- limiting oil and gas development;
- reducing access to federal and state owned lands;
- delaying or canceling certain projects such as offshore drilling, shale development, and pipeline construction;
- limiting or banning the use of hydraulic fracturing;
- denying air-quality permits for drilling; and
- advocating for increased regulations on shale drilling and hydraulic fracturing.

Future anti-development efforts could result in the following:

- blocked development;
- denial or delay of drilling permits;
- shortening of lease terms or reduction in lease size;
- restrictions on installation or operation of gathering or processing facilities;
- restrictions on the use of certain operating practices, such as hydraulic fracturing;
- reduced access to water supplies or restrictions on water disposal;
- reduce access to sand, or other proppants, required for hydraulic fracturing;
- limited access or damage to or destruction of our property;
- legal challenges or lawsuits;
- increased regulation of our business;
- damaging publicity and reputational harm;
- increased costs of doing business;
- reduction in demand for our products; and
- other adverse effects on our ability to develop our properties and expand production.

Costs associated with responding to these initiatives or complying with any new legal or regulatory requirements resulting from these activities could be substantial and not adequately provided for, could have a material adverse effect on our business, financial condition and results of operations. In addition, the use of social media channels can be used to cause rapid, widespread reputational harm.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act establishes federal oversight and regulation of over-the-counter, or OTC, derivatives and requires the Commodity Futures Trading Commission, or CFTC, and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized. In connection with one of its rulemaking proceedings, in December 2013, the CFTC proposed position-limits regulations for certain futures and option contracts in various commodities (including gas) and for swaps that are their economic equivalents. The proposed regulations were supplemented with certain exemptions and guidance in June 2016 and later reproposed in December 2016 (collectively, the "Position Limit Proposals"). The Position Limit Proposals were eventually withdrawn and replaced by a new notice of proposed rulemaking on February 27, 2020, which was ultimately modified and adopted as a final rule, effective March 15, 2021 (the "Position Limit Final Rule"). Certain specified types of hedging and spread positions are exempt from the position limits set forth in the Position Limit Final Rule, provided that such hedging and spread positions satisfy the CFTC's requirements for "bona fide hedging" transactions or "spread transactions," as applicable. Similarly, the CFTC's proposed rule regarding the capital that a swap dealer, or major swap participant, is required to post with respect to its swap business went through several versions from 2011 to 2019 until the CFTC issued a final rule on September 15, 2020. The final rule imposes certain minimum capital requirements and financial reporting requirements on swap dealers and major swap participants and provides specific capital deductions for market risk and credit risk for swaps and security-based swaps entered into by futures commission merchants. In January 2016, the CFTC issued a final rule on margin requirements for uncleared swap transactions, which included an exemption for commercial end-users, entering into uncleared swaps in order to hedge commercial risks affecting their business, from any requirement to post margin to secure such swap transactions (the "CFTC Margin Rule"). In 2017 and 2019, the CFTC issued two no-action letters concerning the minimum transfer amount under the CFTC Margin Rule. After receiving feedback from swap market participants that expressed support for the adoption of regulations consistent with the no-action letters, the CFTC amended the CFTC Margin Rule and adopted a new final rule that became effective on February 24, 2021. In addition, on July 19, 2012, the CFTC issued a final rule authorizing an exception for commercial end-users using swaps to hedge their commercial risks from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a registered derivatives clearing organization and to trade all such swaps on a registered exchange. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations. All of the above regulations and requirements could increase the costs to us of entering into, and lessen the availability of, derivative contracts to hedge or mitigate our exposure to volatility in oil, gas and NGL prices and other commercial risks affecting our business.

It is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements. Moreover, our ability to satisfy the CFTC's requirements for the various exemptions available for a commercial end-user using swaps to hedge or mitigate its commercial risks may affect whether we are required to comply with margin and certain clearing and trade-execution requirements in connection with our derivative activities. If we do not qualify for the commercial end-user exception, we may be required to post margin or clear certain transactions, which could reduce our liquidity and cash available for capital expenditures and our ability to hedge may be impacted. When a final rule on capital requirements is issued, the Dodd-Frank Act may require our current swap counterparties to post additional capital as a result of entering into uncleared derivatives with us, which could increase the costs to us of entering into, and lessen the availability of us to, derivative contracts. The Dodd-Frank Act may also require our current counterparties to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties, and may cause some entities to cease their current business as hedge providers. These changes could reduce the liquidity of the derivatives markets thereby reducing the ability of commercial end-users to have access to derivative contracts to hedge or mitigate their exposure to volatility in oil, gas, and NGL prices. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available capital for other commercial operations purposes), materially alter the terms of future swaps relative to the terms of our existing bilaterally negotiated derivative contracts, and reduce the availability of derivatives to protect us against commercial risks we encounter.

In addition, federal banking regulators have adopted new capital requirements for certain regulated financial institutions in connection with the Basel III Accord. The Federal Reserve Board also issued proposed regulations on September 30, 2016, proposing to impose higher risk-weighted capital requirements on financial institutions active in physical commodities, such as oil and gas. If and when these proposed regulations are fully implemented, financial institutions subject to these higher capital requirements may require that we provide cash or other collateral with respect to our obligations under the financial derivatives and other contracts we may enter into with such financial institutions in order to reduce the amount of capital such financial institutions may have to maintain. Alternatively, financial institutions subject to these capital requirements may price transactions so that we will have to pay a premium to enter into derivatives and other physical commodity transactions in an amount that will compensate the financial institutions for the additional capital costs relating to such derivatives and physical commodity transactions. Rules implementing the Basel III Accord and higher risk-weighted capital requirements could materially reduce our liquidity and increase the cost of derivative contracts and other physical commodity contracts (including through requirements to post collateral, which could adversely affect our available capital for other commercial operations purposes). In addition, certain foreign jurisdictions may adopt or implement laws and regulations relating to margin and central clearing requirements, which in each case may affect our counterparties and the derivatives markets generally.

If we reduce our use of derivative contracts as a result of any of the foregoing regulations or requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, gas, and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, gas, and NGL. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations, or cash flows from operations.

If we were to experience an ownership change, we could be limited in our ability to use net operating losses arising prior to the ownership change to offset future taxable income. In addition, our ability to use net operating loss carry forwards to reduce future tax payments may be limited if our taxable income does not reach sufficient levels.

As of December 31, 2021, we had pre 2018 net operating loss carryforwards or NOLs, for federal income tax purposes of $245.2 million and post 2018 NOLs of $190.8 million. If we were to experience an "ownership change," as determined under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), our ability to offset taxable income arising after the ownership change with NOLs arising prior to the ownership change would be limited, possibly substantially. An ownership change would establish an annual limitation on the amount of our pre-change NOLs we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in our ownership of more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period.

As a result of the Tax Cuts and Jobs Act of 2017, and The Coronavirus Aid, Relief, and Economic Security Act of 2020, NOLs arising before January 1, 2018, and NOLs arising after January 1, 2018, are subject to different rules. Our pre-2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Our NOLs arising in 2018, 2019 and 2020 can generally be carried back five years, carried forward indefinitely and can offset 100% of future taxable income for tax years before January 1, 2021 and up to 80% of future taxable income for tax years after December 31, 2020. Any NOLs arising on or after January 1, 2021, cannot be carried back, can generally be carried forward indefinitely and can offset up to 80% of future taxable income. Our ability to use our NOLs during this period will be dependent on our ability to generate taxable income, and the NOLs could expire before we generate sufficient taxable income.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact our operations.

Our business has become increasingly dependent on digital technologies to conduct certain exploration, development and production activities. We depend on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with our employees and third-party partners. Unauthorized access to our seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in our exploration or production operations. In addition, computer technology controls nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport our production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While we have not experienced significant cyber-attacks, we may suffer such-attacks in the future. Further, as cyber-attacks continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-attacks.

We rely on independent experts and technical or operational service providers over whom we may have limited control.

We use independent contractors to provide us with certain technical assistance and services. We rely upon the owners and operators of rigs and drilling equipment, and upon providers of field services, to drill and develop our prospects to production. We also rely upon the services of other third parties to explore and/or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. Our limited control over the activities and business practices of these service providers, any inability on our part to maintain satisfactory commercial relationships with them or their failure to provide quality services could materially adversely affect our business, results of operations and financial condition.

We depend on our President and CEO and the loss of his services could have an adverse effect on our operations.

We depend to a large extent on Robert L.G. Watson, our President and Chief Executive Officer, for our management, business and financial contacts. Mr. Watson may terminate his employment agreement with us at any time. Mr. Watson is not precluded from working for, with or on behalf of a competitor upon termination of his employment with us. If Mr. Watson were no longer able or willing to act as President and Chief Executive Officer, the loss of his services could have an adverse effect on our operations.

Risks Related to Our Industry

Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows from operations, profitability and growth.

Our revenue, cash flows from operations, profitability and future rate of growth depend substantially upon prevailing prices for oil and gas. Prices also affect the amount of cash flows available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also make it uneconomical for us to increase or even continue current production levels of oil and gas. At the beginning of 2019, OPEC members and some nonmembers, including Russia, renewed pledges to reduce planned production in an effort to draw down a global oversupply and to rebalance supply and demand. As a result of a decrease in global demand for oil and natural gas due to the recent coronavirus outbreak, at the beginning of March 2020, negotiations to extend this pledge were unsuccessful. As a result, Saudi Arabia announced a significant reduction in its export prices and Russia announced that all agreed oil production cuts between members of OPEC and Russia would expire on April 1, 2020. Following these announcements, global oil and natural gas prices declined sharply. Subsequently further negotiations in April 2020 resulted in an agreement to reduce production volumes in an effort to stabilize global oil prices. While prices have recovered from the lows in March 2020, they remained at depressed levels until the war in Ukraine in 2022 elevated prices with many countries enacting sanctions against Russia. We expect ongoing oil price volatility.

Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply and demand for oil and gas, market uncertainty and a variety of other factors beyond our control, including:

- changes in foreign and domestic supply and demand for oil and gas;
- political stability and economic conditions in oil producing countries, particularly in the Middle East, including Saudi Arabia and Russia;

- weather conditions;
- global or national health concerns, including the outbreak of pandemic or contagious disease;
- price and level of foreign imports;
- terrorist activity;
- availability of pipeline and other secondary capacity;
- general economic conditions;
- domestic and foreign governmental regulation; and
- the price and availability of alternative fuel sources.

Events beyond our control, including a global or domestic health crisis, may result in unexpected adverse operating and financial results. In response to the COVID-19 pandemic governments around the world, including U.S. federal, state, and local governments, have imposed restrictions intended to limit the extent and spread of the virus, including travel restrictions, quarantines and business closures. These and other actions could, among other things, impact the ability of our employees and contractors to perform their duties, cause increased technology and security risk due to extended and company-wide telecommuting and lead to disruptions in our permitting activities and critical business relationships. Additionally, the COVID-19 outbreak and governmental restrictions have significantly impacted economic activity and markets and have dramatically reduced current and anticipated demand for oil and natural gas, adversely impacting the prices we receive for our production. The severity and duration of the current COVID-19 outbreak and the potential for future outbreaks are uncertain and difficult to predict. COVID-19 or another similar outbreak may negatively impact our business in numerous ways, including, but not limited to, the following:

- reducing our revenues if the outbreak results in a substantial or prolonged decrease in demand for oil and natural gas due to an economic downturn or recession;
- disrupting our operations if our employees or contractors are unable to work due to illness or if our field operations are suspended or temporarily shut-down or restricted due to measures designed to contain the outbreak;
- disrupting the operations of our midstream service providers, on whom we rely for the gathering, processing and transportation of our production, due to measures designed to contain the outbreak, and/or the difficult economic environment may lead to capital spending constraints, bankruptcy, the closing of facilities or inability to maintain infrastructure, which may adversely affect our ability to market our production, increase our costs, lower the prices we receive, or result in the shut-in of our producing wells or a delay or discontinuation of our development plans; and
- the disruption and instability in the financial markets and the uncertainty in the general business environment may affect our ability to access capital, monetize assets and successfully execute our plans.

The COVID-19 pandemic may also have the effect of heightening many of the other risks set forth in this Item 1A, “Risk Factors”. Any of these factors could have a material adverse effect on our business, operations, financial results and liquidity. Recently, oil and natural gas have declined to historically low levels and we have reduced our planned capital expenditures, delayed our drilling and completion plans and have begun shutting-in most of our producing wells, among other responses. We are unable to predict the ultimate adverse impact of COVID-19 on our business, which will depend on numerous evolving factors and future developments, including the length of time that the pandemic continues, its ongoing effect on the demand for oil and natural gas and the response of the overall economy and the financial markets after governmental restrictions are eased.

Estimates of proved reserves and future net revenue are inherently imprecise.

The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

The estimates of our reserves as of December 31, 2021 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of oil and gas reserves, future net revenue from proved reserves and the present value of our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2021. The average realized sales prices used for purposes of such estimates were $62.00 per Bbl of oil and $1.56 per Mcf of gas. The December 31, 2021 estimates also assume that we will make future capital expenditures of approximately $5.6 million in the aggregate primarily from 2022 through 2026 which are necessary to develop and realize the value of proved reserves on our properties. We cannot assure you that we will have sufficient capital in the future to make these capital expenditures. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of our reserves set forth or incorporated by reference in this report.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated reserves. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

As required by SEC regulations, we based the estimated discounted future net cash flows from our proved reserves as of December 31, 2021 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2021 and costs in effect on December 31, 2021, the date of the estimate. However, actual future net cash flows from our properties will be affected by factors such as:

- supply of and demand for our oil and gas;
- actual prices we receive for our oil and gas;
- our actual operating costs;
- the amount and timing of our capital expenditures;
- the amount and timing of our actual production; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor we use when calculating discounted future net cash flows, which is required by the SEC, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our operations are subject to the numerous risks of oil and gas drilling and production activities.

Our oil and gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil and saltwater spills, gas leaks, ruptures, discharges of toxic gases, underground migration and surface spills or mishandling of any toxic fracture fluids, including chemical additives. In addition, title problems, weather conditions and mechanical difficulties or shortages or delays in delivery of drilling rigs and other equipment could negatively affect our operations. If any of these or other similar industry operating risks occur, we could have substantial losses. Substantial losses also may result from injury or loss of life, severe damage to or destruction of property, clean-up responsibilities, environmental damage, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

We operate in a highly competitive industry which may adversely affect our operations.

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of operations. We must compete for such resources with both major oil and gas companies and independent operators. Many of these competitors have financial and other resources substantially greater than ours. Although we believe our current operating and financial resources are adequate to preclude any significant disruption of our operations, we cannot assure you that such resources will be available to us in the future.

Our oil and gas operations are subject to various U.S. federal, state and local regulations that materially affect our operations.

In the oil and gas industry, matters regulated include permits for drilling and completion operations, drilling and abandonment bonds, reports concerning operations, the spacing of wells and unitization and pooling of properties, the disposal of wastes and taxation. At various times, regulatory agencies have imposed price controls and limitations on production. In order to conserve supplies of oil and gas, these agencies have at times restricted the rates of flow from oil and gas wells below actual production capacity. U.S. federal, state and local laws regulate production, handling, storage, transportation and disposal of oil and gas by-products and other substances and materials produced or used in connection with oil and gas operations. To date, our expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant. We believe that we are in substantial compliance with all applicable laws and regulations. However, the requirements of such laws and regulations are frequently changed. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Recently enacted federal legislation will affect our tax position concerning tax deductions currently available with respect to oil and gas drilling may adversely affect our net earnings.

In December 2017, Congress enacted the budget reconciliation act commonly referred to as the Tax Cuts and Jobs Act, or TCJA. The law made significant changes to U.S. federal income tax laws, including reducing the corporate income tax rate from 35 percent to 21 percent, repealing the corporate alternative minimum tax, or AMT, partially limiting the deductibility of interest expense and NOLs, eliminating the deduction for certain U.S. production activities and allowing the immediate deduction of certain new investments in lieu of depreciation expense over time. Congress subsequently enacted Coronavirus Aid, Relief, and Economic Security Act ("CARES Act") in March 2020, Consolidated Appropriations Act ("CAA") in December 2020, American Rescue Plan Act ("ARPA") in March 2021, which may have temporarily or permanently modified some of the TCJA changes.

Congress has recently considered, is considering, and may continue to consider, legislation that, if adopted in its proposed or similar form, would deprive some companies involved in oil and gas exploration and production activities in certain U.S. federal income tax incentives and deductions currently available to such companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective and whether such changes may apply retroactively. Although we are unable to predict whether any of these or other proposals will ultimately be enacted, the passage of any legislation as a result of these proposals or any other similar changes to U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available to us, and any such change could negatively affect our financial condition and results of operations.

Climate change and regulations related to GHGs could have an adverse effect on our operations and on the demand for oil and gas.

Scientific studies have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. Reports from numerous global and domestic governmental agencies tasked with researching, evaluating, and mitigating the impact of climate change, such as the Sixth Assessment Report of the United Nations Intergovernmental Panel on Climate Change, released in part in August 2021 and February 2022 with a full release expected in September 2022, and the Fourth National Climate Assessment of the U.S. Global Change Research Program, released in full in November 2018, have pointed to GHG emissions as the main driver of atmospheric warming and that climate change is accelerating. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, gas, and refined petroleum products, are considered GHGs. We expect continuing debate, especially in the political arena, over how to address climate change and what policies and regulations are necessary to address the issue.

In response to various scientific studies, governments have begun adopting domestic and international climate change regulations that require reporting and reduction of emissions of GHGs. It is possible that international efforts spear-headed by the United Nations and subsequent domestic and international regulations will have adverse effects on the market for oil, gas and other fossil fuel products as well as adverse effects on the business and operations of companies engaged in the exploration for, and production of, oil, gas and other fossil fuel products. In the United States, at the state level and local level, several states and localities, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of GHGs, such as establishing regional GHG "cap-and-trade" programs. Federally, President Joe Biden has made the reduction of GHG emissions one of the Nation's central ambitions, with the United States rejoining the Paris Agreement in February 2021, under which it pledged to reduce GHG emissions by roughly 25% from 2005 levels by 2025, and then bolstering that commitment in September 2021 when the United States co-launched the Global Methane Pledge with the European Union, pursuant to which it pledged to reduce global methane emissions by at least 30% from 2020 levels by 2030. Various climate change legislative measures have been considered by the U.S. Congress, and the appropriate scope and urgency of regulatory measures to address the impact of GHG emissions will continue to be a broad-spectrum policy issue. Although we are unable to predict the timing, scope and effect of any currently proposed or future legislation, investigations, laws, regulations or treaties regarding climate change and GHG emissions, but the direct and indirect costs of such measures (if enacted) could materially and adversely affect our operations, financial condition and results of operations.

Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur increased operating and compliance costs, or could reduce the demand for the oil and gas that we produce which could result, in our financial condition and results of operations being adversely affected.

In addition, abnormal weather patterns associated with climate change, including severe rainfall events, volatile storms, flooding, droughts, and wildfires, could threaten our production operations and adversely affect our facilities, the scheduling of deliveries, or the cost of supplies needed to run our business

EPA's ground-level ozone standards may result in more stringent regulation of air emissions from, and adverse economic impacts on, our operations.

Effective December 2015, the EPA adopted a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards designed to provide protection of public health and welfare, respectively. The EPA has since issued new area designations with respect to ground-level ozone, and in November 2018, the agency issued final requirements for implementation that apply to state and local agencies. In December 2020, the EPA published a final decision in which it retained the NAAQS of 70 ppb. Since then, the EPA has faced several legal challenges by states and other non-governmental entities to its final decision. On October 29, 2021, the EPA announced that it would reconsider the agency's 2020 decision to retain the 2015 ozone standards and expects for its reconsideration to be complete by the end of 2023. Areas of the country that do not meet the 2015 standard and were thus reclassified as areas of nonattainment are more costly and difficult for operators due to the additional reporting and monitoring requirements imposed on existing sources of emissions,, including those associated with our operations. Moreover, more stringent regulations on constructing new or modified emission sources may require, among other things, installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.

Proposed legislation and regulation under consideration regarding rail transportation could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business.

We presently sell all of our oil production at the lease, either by truck or pipeline, where custody transfers to the purchaser, accordingly it is unknown to us how much of the oil production is ultimately shipped by rail. In response to recent train derailments occurring in the United States, U.S. regulators have considered and implemented rules to address the safety risks of transporting oil by rail. In January, 2014, the NTSB issued a series of recommendations to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) developing an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) auditing shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. In May 2015, the DOT adopted a final rule, developed by PHMSA and FRA, that implemented enhanced tank car and braking standards, designated new operational protocols for trains transporting large volumes of flammable liquids, and established new sampling and testing requirements for energy products placed into transport. Among other deadlines, the DOT's 2015 rule gave U.S. crude oil transporters until January 1, 2018 to phase out or upgrade DOT-111 tank cars. In February 2019, PHMSA, in coordination with FRA, issued a final rule, effective April 1, 2019, that required rail carriers to submit and have approved a comprehensive oil spill response plan for responding to a worst-case discharge of oil or to the substantial threat of discharge. The implementation of these or other regulations that result in new requirements addressing the type, design, specifications or construction of rail cars used to transport oil could result in severe transportation capacity constraints during the period in which new rail cars are retrofitted or constructed to meet new specifications.

We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any regulations that impact the testing or rail transportation of oil could increase our costs of doing business and limit our ability to transport and sell our oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows from operations.

Risks Related to Our Capital Stock

Future issuance of additional shares of common stock or Series A Preferred Stock could cause dilution of ownership interests and adversely affect our stock price.

We are currently authorized to issue 20,000,000 shares of common stock and 1,000,000 shares of our preferred stock with such rights as determined by our board of directors. Of our 1,000,000 authorized shares of preferred stock, we are currently authorized to issue 685,505 shares of preferred stock designated as Series A Preferred Stock. On January 3, 2022 (the "Initial Issuance Date"), we issued all 685,505 shares of our Series A Preferred Stock to a single stockholder.

In the future, and subject to the voting and consent restrictions set forth in the certificate of designation establishing the Series A Preferred Stock (the "Preferred Stock Certificate"), we may increase our authorized shares of common stock or preferred stock or issue previously authorized and unissued securities, resulting in the dilution of the ownership interests of current stockholders. The potential issuance of any such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of common stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock or preferred stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

Without the affirmative vote or consent of the holders of at least a majority in voting power of the shares of Series A Preferred Stock outstanding at the time, voting together as a separate class, we cannot authorize, create, increase the authorized amount of, or issue any class or series of shares of our capital stock that ranks senior to or on parity with the Series A Preferred Stock.

Pursuant to the terms of the Preferred Stock Certificate, so long as any shares of Series A Preferred Stock remain outstanding, we are prohibited from authorizing or creating, or increasing the authorized amount of, or issuing any class or series of our capital stock that ranks senior to or on parity with the Series A Preferred Stock (including additional shares of Series A Preferred Stock) as to dividend rights, redemption rights or distribution rights, or creating, authorizing, or issuing any obligation or security convertible into or evidencing the right to purchase any shares of our capital stock that ranks senior to or on parity with the Series A Preferred Stock (including the Series A Preferred Stock) without the affirmative vote or consent of the holders of at least a majority in voting power of the shares of Series A Preferred Stock outstanding at the time, voting together as a separate class.

Currently, all of our Series A Preferred Stock is held of record by a single stockholder, AG Energy Funding, LLC, a Delaware limited liability company ("AGEF").

We will not pay dividends on our common stock for the foreseeable future. Our ability to declare or pay dividends on, or purchase, redeem or otherwise acquire, shares of our common stock will be subject to certain restrictions in the event that we fail to pay dividends on our preferred stock.

We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. In addition, our credit facilities prohibit us from paying dividends and making other cash distributions.

In the event we desire to pay cash dividends, our ability to declare or pay dividends on shares of our common stock will be restricted by the order of priority for distributions set forth in Section 3 of the Preferred Stock Certificate. As described in the Preferred Stock Certificate, the Series A Preferred Stock, with respect to all dividends or distributions of any kind or character to our stockholders, ranks: (i) senior to our common stock and each other class or series of our capital stock established after the Initial Issuance Date, the terms of which do not expressly provide that such class or series ranks senior to or on a parity with the Series A Preferred Stock as to dividend rights, redemption rights or distribution rights; (ii) on a parity with any class or series of our capital stock established after the Initial Issue Date, the terms of which expressly provide that such class or series will rank on parity with the Series A Preferred Stock as to dividend rights, redemption rights or distribution rights; and (iii) junior to our existing and future indebtedness and liabilities.

As of January 3, 2022, we have issued all 685,505 shares of our Series A Preferred Stock to AGEF. Shares of our preferred stock vote together as a single class with our common stock, and each share of preferred stock entitles the holder thereof to 69 votes. As such, AGEF's Series A Preferred Stock ownership entitles it to approximately 85% of the voting power of our outstanding capital stock.

Shares eligible for future sale may depress our stock price.

At December 31, 2021, we had 8,421,910 shares of common stock outstanding of which 208,020 shares were held by affiliates and, in addition, 54,222 shares subject to outstanding options granted under stock option plans, all of which were vested at December 31, 2021.

As of January 3, 2022, we had 685,505 shares of our preferred stock outstanding, all of which is held by AGEF.

All of the of the shares of common stock held by affiliates are restricted or are control securities under Rule 144 promulgated under the Securities Act. The shares of common stock issuable upon exercise of stock options have been registered under the Securities Act. Sales of shares of common stock under Rule 144 or another exemption under the Securities Act or pursuant to a registration statement could have a material adverse effect on the price of our common stock and could impair our ability to raise additional capital through the sale of equity securities.

The price of our common stock has been volatile and could continue to fluctuate substantially.

Our common stock is traded on the highest tier of the over-the-counter market (the “OTCQX”. The market price of our common stock has been volatile and could fluctuate substantially based on a variety of factors, including the following:

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the oil and gas industry;
- sales of common stock or other actions by our stockholders;
- additions or departures of key management personnel;
- commencement of or involvement in litigation;
- speculation in the press or investment community regarding our business;
- an inability to maintain the listing of our common stock on a national securities exchange;
- market conditions; and
- analysts’ estimates and other events in the oil and gas industry.

We may issue shares of preferred stock with greater rights than our common stock.

Subject to market listing rules, our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of our common stock. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than our common stock.

As of January 3, 2022, we have issued 685,505 shares of our Series A Preferred Stock to AGEF. The Series A Preferred Stock has the terms set forth in the Company's filed Preferred Stock Certificate of Designation. Pursuant to that certificate, any proceeds distributed to the Company's stockholders or otherwise received in respect of the capital stock of the Company in a merger or other liquidity event will be allocated among the Series A Preferred Stock and the Company's common stock as follows: (1) first, 100% to the Series A Preferred Stock until the Series A Preferred Stock has received $100 million of proceeds in the aggregate (the "Tier One Preference Amount"), (2) second, 95% to the Series A Preferred Stock and 5% to the Company's common stock until the Series A Preferred Stock has received $137.1 million, plus a 6.0% annual rate of return thereon from the date hereof; (3) thereafter, 75% to the Series A Preferred Stock and 25% to the Company's common stock. The Exchange Agreement entered into in connection with the Restructuring also provides for the potential funding by AGEF of an additional amount up to $12.0 million, if agreed to by AGEF and the disinterested members of the Company's Board of Directors. Any such additional amount funded would result in an increase to the Tier One Preference Amount equal to 1.5 x the amount of such additional funding. The shares of Series A Preferred Stock vote together as a single class with the Company's common stock, and each share of Series A Preferred Stock entitles the holder thereof to 69 votes. Accordingly, AGEF's ownership of the Series A Preferred Stock entitle it to approximately 85% of the voting power of the Company's current outstanding capital stock.

Anti-takeover provisions could make a third party acquisition of us difficult.

Our articles of incorporation and bylaws provide for a classified board of directors, with each member serving a three-year term, and eliminate the ability of stockholders to call special meetings or take action by written consent. Each of the provisions in our articles of incorporation and bylaws could make it more difficult for a third party to acquire us without the approval of our board. In addition, the Nevada corporate statute also contains certain provisions that could make an acquisition by a third party more difficult.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Exploratory and Developmental Acreage

Our principal oil and gas properties consist of producing and non-producing oil and gas leases, including reserves of oil and gas in place. The following table sets forth our developed and undeveloped acreage and fee mineral acreage as of December 31, 2021.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage (1)		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres (2)
Permian/Delaware Basin	18,234	13,673	12,723	8,374	9,556	2,391	24,438
Rocky Mountain (3)	5,442	3,892	2,907	1,676	1,720	100	5,668
Total	23,676	17,565	15,630	10,050	11,276	2,491	30,106

(1) Fee mineral acreage represents fee simple absolute ownership of the mineral estate or fraction thereof.
(2) Includes 640 net acres in the Permian Basin region that are included in both developed and fee mineral acres.
(3) All Rocky Mountain properties were sold in January 2022. See Note 14 "Subsequent Events."

The following table sets forth Abraxas' net undeveloped acreage subject to expiration by year:

	2022	2023	2024	2025	2026
Permian/Delaware Basin	62	5	-	-	-
Rocky Mountain (1)	-	-	-	-	-
Total	62	5	-	-	-

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2021:

	Productive Wells			
	Oil		Gas	
	Gross	Net	Gross	Net
Permian/Delaware Basin	62	53	43	31
Rocky Mountain (1)	64	38	9	5
	126	91	52	36

(1)All Rocky Mountain properties were sold in January 2022. See Note 14 “Subsequent Events.”

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Reserves Information

The estimation and disclosure requirements we employ conform to the definition of proved reserves with the Modernization of Oil and Gas Reporting rules, which were issued by the SEC in 2008. This accounting standard requires that the average first-day-of-the-month price during the 12-month period preceding the end of the year be used when estimating reserve quantities and permits the use of reliable technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes.

The Company's proved oil and gas reserves have been estimated by an independent petroleum engineering firm, DeGolyer & MacNaughton, as of December 31, 2020 and 2021, assisted by the engineering and operations departments of the Company. For the year ended December 31, 2021, DeGolyer & MacNaughton, of Dallas, Texas estimated reserves for our Permian/Delaware Basin comprising approximately 60% of the PV-10 of our proved oil and gas reserves. Proved reserves for the remaining 40% of our properties, primarily our Rocky Mountain properties that were sold in January 2022, were estimated by Abraxas personnel because we determined that it was not practical for DeGolyer & MacNaughton to prepare reserves estimates for these properties as they are located in a widely dispersed geographic area and have relatively low value, or were subsequently sold. DeGolyer & MacNaughton's reserve report as of December 31, 2021 included a total of 65 properties and our internal report included 142 properties, including 67 Bakken properties sold in January 2022. See Note 14 "Subsequent Events".

The technical personnel responsible for preparing the reserve estimates at DeGolyer & MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer & MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists. They do not own an interest in any of our properties and are not employed on a contingent fee basis. All reports by DeGolyer & MacNaughton were developed utilizing their own geological and engineering data, supplemented by data provided by Abraxas. The report of DeGolyer & MacNaughton, datedFebruary 4, 2022, which contains further discussions of the reserve estimates and evaluations prepared by DeGolyer & MacNaughton as well as the qualifications of DeGolyer & MacNaughton's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of reserves at December 31, 2021 were assisted by the engineering department of Abraxas which is directly responsible for Abraxas' reserve evaluation process. The Vice President of Engineering manages this department and is the primary technical person responsible for this process. The Vice President of Engineering holds a Bachelor of Science degree in Petroleum Engineering and is a Registered Professional Engineer in the State of Texas; he has 42 years of experience in reserve evaluations. The operations department of Abraxas also assisted in the process. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages, were obtained from other departments within Abraxas.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and Financial Accounting Standards Board, or FASB, guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas and the timing and amount of future net revenues to be received therefrom. Such estimates are not precise and are based on assumptions regarding a variety of factors, many of which are variable and uncertain. Proved oil and gas reserves are the estimated quantities of oil and 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. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations or de-escalations except by contractual arrangements. For the year ended December 31, 2021, commodity prices over the prior 12-month period and year end costs were used in estimating future net cash flows.

The following table sets forth certain information regarding estimates of our oil and gas reserves as of December 31, 2021. All of our reserves are located in the United States.

Summary of Oil, NGL and Gas Reserves
As of December 31, 2021

Reserve Category	Oil (MBbls)	NGL (MBbls)	Gas (MMcf)	Oil equivalents (MBoe)
Proved				
Developed	6,883	2,914	30,158	14,823
Undeveloped	-	-	-	-
Total Proved	6,883	2,914	30,158	14,823

As of December 31, 2021, we did not recognize any proved undeveloped reserves. During 2021, our proved undeveloped reserves are excluded from our total proved reserves primarily due to capital constraints.

Our estimates of proved developed reserves at December 31, 2020 and 2021, and estimates of future net cash flows and discounted future net cash flows from proved reserves are presented in the Supplemental Information.

We have not filed information with a federal authority or agency with respect to our estimated total proved reserves at December 31, 2021. We report gross proved reserves of operated properties in the United States to the U.S. Department of Energy on an annual basis; these reported reserves are derived from the same data used to estimate and report proved reserves in this report.

The process of estimating oil and gas reserves is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves set forth or incorporated by reference in this report. We may also adjust estimates of reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. In particular, estimates of oil and gas reserves, future net revenue from reserves and the PV-10 thereof for the oil and gas properties described in this report are based on the assumption that future oil and gas prices remain the same as oil and gas prices utilized in the December 31, 2021 report. The average realized sales prices used for purposes of such estimates were $62.00 per Bbl of oil and $1.56 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $5.6 million in the aggregate primarily in the years 2022 through 2026, which are necessary to develop and realize the value of proved reserves on our properties. Any significant variance in actual results from these assumptions could also materially affect the estimated quantity and value of reserves set forth herein.

You should not assume that the present value of future net revenues referred to in this report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are calculated using the average first-day-of-the-month price over the prior 12-month period. Costs used in the estimated discounted future net cash flows are costs as of the end of the period. Because we use the full cost method to account for our oil and gas operations, we are susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. This is known as a “ceiling limitation write-down.” This charge does not impact cash flows from operating activities but does reduce our stockholders’ equity and reported earnings. We have experienced ceiling limitation write-downs in the past and we cannot assure you that we will not experience additional ceiling limitation write-downs in the future. As of December 31, 2021 the net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves. As of December 31, 2021, the Company’s net capitalzed costs of oil and gas properties did not exceed the present value of our estimated proved reserves.

For more information regarding the full cost method of accounting, you should read the information under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies.”

Actual future prices and costs may be materially higher or lower than the prices and costs used in the reserve report. Any changes in consumption by gas purchasers or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. Our effective interest rate on borrowings at various times and the risks associated with us or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

Proved Undeveloped Reserves

Due to the unavailability of capital, the Company did not recognize PUD in 2020 or 2021.

Reconciliation of Standardized Measure to PV-10

PV-10 is the estimated present value of the future net revenues from our proved oil and gas reserves before income taxes discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

The following table provides a reconciliation of the standardized measure of discounted future net cash flows to PV-10 at December 31, 2020 and 2021:

	December 31,	
	2020	2021
	(In thousands)	
Standardized measure of discounted future net cash flows	$ 106,684	$ 153,275
Present value of future income taxes discounted at 10%	-	-
PV-10	$ 106,684	$ 153,275

Oil and Gas Production, Sales Prices and Production Costs

The following table presents our net oil, gas and NGL production, the average sales price per Bbl of oil and NGL and per Mcf of gas produced and the average cost of production per Boe of production sold, for the two years ended December 31, 2020 and 2021, by our major operating regions:

	Years Ended December 31,	
	2020	2021
Oil Production (Bbl)		
Permian	596,680	498,225
Rocky Mountain (4)	536,032	458,829
Total	1,132,712	957,054
Gas Production (Mcf)		
Permian	689,684	1,593,725
Rocky Mountain (4)	1,444,753	1,838,495
Total	2,134,437	3,432,220
NGL Production (Bbl)		
Permian	67,586	109,970
Rocky Mountain (4)	245,469	348,874
Total	313,055	458,844
Total Production (Boe) (1)	1,801,507	1,150,118
Average sales price per Bbl of oil (2)		
Permian	$ 38.36	$ 65.57
Rocky Mountain (4)	$ 35.58	$ 62.25
Composite	$ 37.05	$ 63.98
Average sales price per Mcf of gas		
Permian	$ 0.49	$ 2.81
Rocky Mountain (4)	$ 0.17	$ 2.27
Composite	$ 0.27	$ 2.52
Average sales price per Bbl of NGL		
Permian	$ 2.42	$ 19.83
Rocky Mountain (4)	$ 1.08	$ 17.59
Composite	$ 1.37	$ 18.09
Average sales price per Boe (2)	$ 23.86	$ 38.95
Average cost of production per Boe produced (3)		
Permian	$ 12.14	$ 10.85
Rocky Mountain (4)	$ 7.03	$ 7.33
Composite	$ 9.24	$ 8.85

(1)Oil and gas were combined by converting gas to Boe on the basis of 6 Mcf of gas to 1 Bbl of oil.

(2)Before the impact of hedging activities.

(3)Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

(4)All Rocky Mountain properties were sold January 3, 2022. See Note 14 “Subsequent Events.”

Within the above major operating regions, the Rocky Mountain and the Permian/Delaware regions represented more than 15% of our proved reserves as of December 31, 2021. The following is a summary, by product sold, for each primary field in these regions, which represented 15% or more of our total proved reserves as of December 31, 2021, for the two years ended December 31, 2020 and 2021

	Years Ended December 31,	
	2020	2021
Rocky Mountain Region (3)		
Oil production (Bbls)		
Bakken/Three Forks	509,518	452,181
Gas production (Mcf)		
Bakken/Three Forks	1,428,355	1,824,851
NGL production (Bbls)		
Bakken/Three Forks	244,835	384,627
Average sales price per Bbl of oil (1)		
Bakken/Three Forks	$ 35.78	$ 62.36
Average sales price of per Mcf of gas		
Bakken/Three Forks	$ 0.17	$ 2.27
Average sales price per Bbl of NGL		
Bakken/Three Forks	$ 1.08	$ 17.60
Average cost of production per Boe produced (2)	$ 5.96	$ 6.86
Permian Region		
Oil production (Bbls)	538,086	451,840
Wolfcamp		
Gas Production (Mcf)	375,507	438,701
Wolfcamp		
NGL production (Bbls)	55,706	62,417
Wolfcamp		
Average sales price per Bbl of oil (1)	$ 38.64	$ 65.70
Wolfcamp		
Average sales price of per Mcf of gas	$ 0.14	$ 2.35
Wolfcamp		
Average sales price per Bbl of NGL	$ 1.70	$ 18.95
Wolfcamp		
Average cost of production per Boe produced (2)	$ 12.97	$ 13.26

(1) Before the impact of hedging activities.

(2) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

(3) All Rocky Mountain properties were sold January 3, 2022. See Note 14 “Subsequent Events.”

Drilling Activities

The Company did not drill or complete any wells during the two years ended December 31, 2021:.

Present Activities

Due to our lack of capital resources, we did not drill or complete any wells in 2020 or 2021.

Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, and consist of approximately 21,000 square feet. We own the building which is subject to a real estate lien note.

Other Properties

We own 1.5 acres of land and an office building in Ward County, Texas. We owned a lot in Niobrara County, Wyoming, which was sold in January 2022. . We owned 582 acres of land, with shop and office, in McKenzie County, North Dakota. We own 15 vehicles which are used in the field by employees. We also own a workover rig, which is used for servicing our wells. Raven Drilling owns a 2000 HP drilling rig. In North Dakota, we owned three houses and a man-camp to house rig crews. All of our North Dakota assets were sold on January 3, 2022. See Note 14 “Subsequent Events.”

Item 3. Legal Proceedings

From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2021, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on our financial condition.

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 OTCQX Stock Market under the symbol " AXAS." The following table sets forth certain information as to the high and low sales price quoted for our common stock.

		High	Low
Period			
2020			
	First Quarter	$ 8.40	$ 1.80
	Second Quarter	11.00	2.20
	Third Quarter	5.20	2.80
	Fourth Quarter	5.60	1.41
2021	First Quarter	$ 4.99	$ 2.23
	Second Quarter	3.57	1.85
	Third Quarter	4.10	1.23
	Fourth Quarter	2.00	0.55
2022	First Quarter (Through March XX, 2022)	$ 4.94	$ 0.56

Holders

As of March 18, 2022, we had 8,421,910 shares of common stock outstanding held by approximately 112 stockholders of record, and 685,505 shares of Series A Preferred Stock outstanding held by one stockholder of record.

Dividends

We have not paid any cash dividends on our common stock and it is not presently determinable when, if ever, we will pay cash dividends in the future. In addition, our credit facilities prohibited the payment of cash dividends on our common stock.

Item 6. Selected Financial Data

The following selected financial data is derived from our Consolidated Financial Statements as of and for the years ended December 31, 2017 through 2021. The data should be read in conjunction with our Consolidated Financial Statements and Notes thereto and other financial information included herein. See "Financial Statements and Supplementary Data" in Item 8. All share and per share amounts reflect the retroactive treatment of the Reverse Stock Split, see Note 3 to our Consolidated Financial Statements.

	Year Ended December 31,				
	2017	2018	2019	2020	2021
	(In thousands, except per share data)				
Total revenue	$ 86,264	$ 149,167	$ 129,146	$ 43,043	$ 78,858
Net (loss) income	$ 16,006	$ 57,821	$ (65,004)	$ (184,522)	$ (44,567)
Net (loss) income from operations	$ 16,006	$ 57,821	$ (65,004) (1)	$ (184,522) (2)	$ (44,567)
Net (loss) income per common share - Diluted	$ 2.00	$ 6.80	$ (7.80)	$ (22.01)	$ (5.30)
Weighted average shares outstanding - Diluted	8,142	8,384	8,315	8,382	8,408
Total assets	$ 273,806	$ 424,741	$ 354,631	$ 157,761	$ 130,476
Long-term debt, excluding current maturities	$ 87,354	$ 181,942	$ 192,718	$ 2,515	$ 2,205
Total stockholders' equity	$ 106,308	$ 166,510	$ 103,819	$ (72,967)	$ (116,588)

(1) Includes proved property impairment of $51.3 million.
(2) Includes proved property impairment of $187.0 million.

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

The following is a discussion of our consolidated financial condition, results of operations, liquidity and capital resources. This discussion should be read in conjunction with our Consolidated Financial Statements and the Notes thereto. See "Financial Statements and Supplementary Data" in Item 8.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States. Historically, we have grown through the acquisition and subsequent development and exploitation of producing properties, principally through the redevelopment of old fields utilizing new technologies such as modern log analysis and reservoir modeling techniques as well as 3-D seismic surveys and horizontal drilling. As a result of these activities, we believe that we have a number of development opportunities on our properties. In addition, we intend to expand upon our development activities with complementary acreage acquisitions in our core areas of operation. Success in our development and exploration activities is critical in the maintenance and growth of our current production levels and associated reserves.

Our financial results depend upon many factors which significantly affect our results of operations including the following:

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Arrangements. The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Oil and gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL, and gas prices in the future. The market price of oil, NGL and gas in 2022 will impact the amount of cash generated from operating activities, which will in turn impact our financial position. As of March 18, 2022, the NYMEX oil and gas price was $104.70 per Bbl of oil and $4.86 per Mcf of gas, respectively.

During 2021, the NYMEX future price for oil averaged $68.11 per barrel as compared to $39.57 per barrel in 2020 and the NYMEX future spot price for gas averaged $3.73 per Mcf compared to $2.13 per Mcf in 2020. Prices closed on December 31, 2021 at $75.21 per Bbl of oil and $3.73 per Mcf of gas. If commodity prices decline from these levels, our revenue and cash flows from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If oil and gas prices decline, our revenues, profitability and cash flows from operations will also likely decrease which could cause us to alter our business plans, including reducing our drilling activities. Such declines will require us to write down the carrying value of our oil and gas assets which will also cause a reduction in net income.

The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;
- adjustments for BTU content;

- quality of the hydrocarbons; and
- gathering, processing and transportation costs.

The following table sets forth our average differentials for the years ended December 31, 2020 and 2021:

	Oil		Gas	
	2020	2021	2020	2021
Average realized price	$ 37.05	$ 63.98	$ 0.27	$ 2.52
Average NYMEX price	$ 39.57	$ 68.11	$ 2.13	$ 3.73
Differential	$ (2.52)	$ (4.13)	$ (1.86)	$ (1.21)

(1) Average realized prices are before the impact of hedging activities.

The Company's derivative contracts as of December 31, 2020 and during 2021 consisted of NYMEX-based fixed price swaps and basis differential swaps. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. All derivative contracts were cancelled or expired in 2021.

In April 2021, we received notice that certain of our hedging agreements were being terminated as a result of events of default under the First Lien Credit Facility, and we voluntarily terminated most of our other hedging arrangements. As a result of the settlement of the terminated hedges, we had outstanding obligations of $8.0 million. The settlement values of the terminated hedges were determined at various dates between April 15 and April 30, 2021. These obligations were added to the balance of the First Lien Credit Facility and accrued interest at the default interest rate of 8.75%, until they were repaid. Our remaining hedging agreement expired on December 31, 2021.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve report as of December 31, 2021, our average annual estimated decline rate for our net proved developed producing reserves is 20%, 15% , 13% , 12% and 11% in 2022, 2023, 2024, 2025 and 2026, respectively, 9% in the following five years, and approximately 10% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

In addition to our ability to successfully drill wells, we must also market our production which depends substantially on the availability, proximity and capacity of gathering systems, pipelines and processing facilities, which are also known as midstream facilities, owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations could be adversely affected. Our principal areas of operation have experienced substantial development in recent years, and this has made it more difficult for providers of midstream infrastructure and services to keep pace with the corresponding increases in field-wide production. The ultimate timing and availability of adequate infrastructure is not within our control and we could experience capacity constraints for extended periods of time that would negatively impact our ability to meet our production targets. Weather, regulatory developments and other factors also affect the adequacy of midstream infrastructure.

We had cash capital expenditures during 2021 of approximately $0.9 million. Due to lack of capital we suspended our planned capital expenditures for 2021. This suspension of our capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources the results of our exploitation efforts, our financial results and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the years ended December 31, 2020 and 2021:

	2020	**2021**
Total Production (Mboe)	1,801	2,023
Average daily production (Boepd)	4,922	5,545
% Oil	63%	47%

Availability of Capital. As described more fully under "Liquidity and Capital Resources" below, our sources of capital are cash flows from operating activities, cash on hand, proceeds from the sale of properties, monetizing of derivative instruments, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all.

Borrowings and Interest. At December 31, 2021, we had a total of $71.4 million outstanding under our First Lien Credit Facility, $134.9 million under our Second Lien Credit Facility, and total indebtedness of $218.8 million, including a $10.0 million exit fee. Our First Lien Credit Facility was settled in January 2022 with proceeds from a property sale of the same date. On January 3, 2022 our Second Lien Credit Facility and exit fee were converted to preferred stock, resulting in the Company having no debt, except the Real Estate Lien note on our headquarters building

Exploration and Development Activity. We believe that our asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2021, we operated properties comprising approximately 97% of the Boe's of our estimated net proved reserves, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2021, we drilled or participated in 92 gross (42.8 net) wells all of which were commercially productive.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, finance, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flows from operations will decline. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Results of Operations

	Year Ended December 31, (in thousands)	
	2020	**2021**
Operating revenue (1):		
Oil sales	$ 41,969	$ 61,228
Gas sales	586	8,656
NGL sales	429	8,952
Other income	59	22
Total revenues	$ 43,043	$ 78,858
Operating (loss) income	$ (199,418)	$ 30,484
Oil sales (MBbls)	1,133	957
Gas sales (MMcf)	2,134	3,432
NGL sales (MBbls)	313	495
Oil equivalents (MBoe)	1,801	2,023
Average oil sales price (per Bbl)(1)	$ 37.05	$ 63.98
Average gas sales price (per Mcf)	$ 0.27	$ 2.52
Average NGL price (per Bbl)	$ 1.37	$ 18.09
Average oil equivalent sales price (per Boe)	$ 23.86	$ 38.95

(1)Revenue and average sales prices are before the impact of hedging activities, if applicable.

Comparison of Year Ended December 31, 2021 to Year Ended December 31, 2020

Revenue. During the year ended December 31, 2021, revenue increased to $78.9 million from $43.0 million in 2020. Higher commodity prices for all products in 2021 contributed $41.8 million to revenue. Lower oil sales volumes negatively impacted revenue by $6.5 million, partially offset by higher gas and NGL volumes which contributed $0.6 million to revenue.

Oil sales volumes decreased to 957 MBbls for the year ended December 31, 2021 from 1,133 MBbls for the same period of 2020. The decrease in oil sales volumes was primarily due to natural field declines and the sale of various non-operated properties in 2021, partially offset by wells that were shut-in in early 2020 due to low prices being back on production in 2021. No new wells were brought on line in 2021. Gas sales volumes increased to 3,432 MMcf for the year ended December 31, 2021 compared to 2,134 MMcf for the year ended December 31, 2020. NGL sales increased to 495 MBbls for the year ended December 31, 2021 compared to 313 MBbls for the same period of 2020. The increase in gas and NGL volumes was primarily due to wells that were shut in during early 2020 being back on production in 2021.

Lease Operating Expenses ("LOE"). LOE for the year ended December 31, 2021 increased to $17.9 million from $16.5 million in 2020. The increase in LOE was primarily due to the increased cost of wells brought back on production that were shut in during the first part of 2020. LOE per Boe for the year ended December 31, 2021 was $8.85 compared to $9.14 for the same period of 2020. The decrease in LOE per Boe was attributable to higher sales volumes in 2021 as compared to 2020**.**

Production and Ad Valorem Taxes. Production and ad valorem taxes for the year ended December 31, 2021 increased to $6.2 million from $4.6 million in 2020. The increase was primarily due to higher realized prices and sales volumes in 2021 as compared to 2020. Production and ad valorem taxes as a percentage of oil and gas revenue were 8% in 2021 compared to 11% for the same period of 2020. The decrease in ad valorem taxes as a percentage of revenue was primarily due increased production in Texas, which has a lower tax rate.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, decreased to $7.2 million for the year ended December 31, 2021 from $7.5 million in 2020. G&A expense per Boe was $3.54 for the year ended December 31, 2021 compared to $4.15 for the same period of 2020. The reduction in total G&A expense was primarily due to a reduction in personnel in the corporate office, as well as reductions in salaries. Officer salaries were reduced by 20% effective March 1, 2020, and our CEO took an additional 20% reduction in salary effective April 1, 2020. The decrease per Boe was primarily due to higher sales volumes.

Stock-Based Compensation. Restricted stock, stock options and performance based restricted stock granted to employees and directors are valued at the date of grant and expense is recognized over the securities vesting period. Stock-based compensation decreased to $0.9 million for the year ended December 31, 2021 compared to $1.3 million for the same period of 2020. The decrease was primarily due to the cancellation, forfeiture, and expiration of stock options as well as a significant portion of stock grants having been fully amortized with no awards having been granted in 2020 or 2021.

Depreciation, Depletion, and Amortization ("DD&A") Expenses. DD&A expense excluding accretion of future site restoration, decreased to $15.3 million for the year ended December 31, 2021 from $24.4 million in 2020. The decrease was primarily due to lower future development cost included in the December 31, 2021 reserve report, due to the exclusion of the development cost of PUDs. The full cost pool was also reduced by significant impairments in 2020. DD&A expense per Boe for the year ended December 31, 2021 was $7.57 compared to $13.56 in the same period of 2020. The decrease in DD&A expense per Boe was primarily due to a lower full cost pool as the result of the impairment incurred as of December 31, 2019 and in 2020.

Interest Expense. Interest expense increased to $35.8 million in 2021 from $21.3 million for 2020. The increase was primarily due to higher debt levels in 2021 as compared to 2020, as well as higher overall interest rates in 2021 as compared to 2020. In 2021, the interest rate on our First Lien Credit facility averaged 6.2% as compared to 3.6% in 2020. The average interest rate on the Second Lien Credit Facility for the year ended December 31, 2021 was 16.4% as compared to 15.8% in 2020. $22.2 million of interest on the Second Lien Credit Facility was paid in kind in 2021 compared to $12.7 million in 2020. Default interest was charged on both the First Lien and Second Lien Credit Facilities beginning in April 2021 as a result of the default that occurred.

Income Taxes. Due to losses in the periods and loss carry forwards, we did not recognize any income tax expense for the years ended December 31, 2021 and 2020.

(Gain) loss on Derivative Contracts. Derivative gains or losses are determined by actual derivative settle"ments during the period and by periodic mark to market valuation of derivative contracts in place. We have elected not to apply hedge accounting to our derivative contracts as prescribed by Accounting Standards Codification 815, Derivatives and Hedging "ASC 815", therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consisted of fixed price swaps and basis differential swaps in 2021 and 2020. The net estimated value of our commodity derivative contracts was a liability of approximately $0.4 million as of December 31, 2021. When our derivative contract prices are higher than prevailing market prices, we recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. For the year ended December 31, 2021, we incurred a loss of $33.0 million, including a loss of $7.1 million related to cancelled contracts. For the year ended December 31, 2020, we recognized a gain on our derivative contracts of $42.9 million.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flows from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. For the year ended December 31, 2021, the net capitalized cost of our oil and gas properties did not exceed the future net revenues from our estimated proved reserves. For the year ended December 31, 2020, the net capitalized cost of our oil and gas properties exceeded the future net revenues from our estimated proved reserves resulting in the recording of an impairment of $187.0 million during 2020. The year-end amounts were calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices utilized for the year ended 2021 which were $62.00 per Bbl of oil and $1.56 per Mcf of gas as adjusted to reflect the expected realized prices for our oil and gas reserves. The twelve month first-day-of-the-month average oil and gas prices utilized for the year ended 2020 were $39.54 per Bbl of oil and $2.03 per Mcf of gas as adjusted to reflect the expected realized prices for our oil and gas reserves.

Working Capital (Deficit). At December 31, 2021, our current liabilities of $240.0 million exceeded our current assets of $24.1 million resulting in a working capital deficit of $216.0 million. This compares to a working capital deficit of $195.3 million at December 31, 2020. Current assets at December 31, 2021 primarily consisted of cash of $10.0, accounts receivable of $13.5 million, and other current assets of $0.5 million. Current liabilities at December 31, 2021 primarily consisted of trade payables of $4.7 million, revenues due third parties of $13.3 million, current maturities of long-term debt of $212.7 million, the then-current amount of our derivative liability of $0.4 million and termination fee for derivative contracts of $8.0 million, and accrued expenses of $0.8 million.

Capital Expenditures. Capital expenditures in 2020 and 2021 were $5.4 million and $1.3 million, respectively. The table below sets forth the components of these capital expenditures:

	Years Ended December 31,	
	2020	**2021**
	(in thousands)	
Expenditure category:		
Exploration/Development	$ 5,238	$ 1,145
Acquisitions	-	-
Facilities and other	162	180
	$ 5,400	$ 1,325

During 2020 and 2021 capital expenditures were primarily expenditures on our existing properties. We also performed extensive workovers on several wells in 2020. The level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows from operations will decrease which may result in a reduction of capital expenditure. Due to capital expenditure limits imposed by our credit facilities, we have not adopted a capital drilling budget for 2022. If we cannot incur significant capital expenditure, we will not be able to offset oil and gas production decreases caused by natural field declines.

Sources and Uses of Capital. The net funds provided by and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	Years Ended December 31,	
	2020	**2021**
	(in thousands)	
Net cash provided by operating activities	$ 15,985	$ 32,419
Net cash (used in) investing activities	(12,557)	(518)
Net cash (used in) provided by financing activities	(653)	(24,642)
	$ 2,775	$ 7,259

Operating activities for the year ended December 31, 2021 provided $32.4 million in cash compared to $16.0 million in 2020. The increase was primarily due to lower net loss due to higher commodity prices and production volumes. Investing activities used $0.5 million in 2021 primarily for the development of our existing properties. Cash expenditures for the year ended December 31, 2021 included a decrease of $2.2 million in the future site restoration account related to properties sold, and proceeds from sales on non-oil and gas and oil and gas properties of $0.9 million and an increase in accounts payable related to capital expenditures of $0.05 million resulting in accrual based capital expenditures incurred during the period of $1.3 million.

Operating activities for the year ended December 31, 2020 provided $16.0 million in cash. The reduction from 2019 was primarily due to lower net income due to lower commodity prices and lower production volumes. Investing activities used $12.6 million in 2020, primarily for the development of our existing properties. Cash expenditures for the year ended December 31, 2020 included a decrease in the accounts payable balance related to capital expenditures of $7.2 million, resulting in accrual based capital expenditures incurred during the period of $5.4 million.

Future Capital Resources. Our principal sources of capital going forward, are cash flows from operations, proceeds from the sale of properties and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete financing on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. A decrease in commodity prices from current levels would likely reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flows from operations will decline.

Contractual Obligations. We are committed to making cash payments in the future on the following types of agreements:

- Long-term debt

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2021:

Contractual Obligations (In thousands)	**Payments due in the twelve month periods ended:**				
	Total	**December 31, 2022**	**December 31, 2023-2024**	**December 31, 2025-2026**	**Thereafter**
Long-term debt (1),(4)	$ 226,844	$ 224,639	$ 2,205	$ -	$ -
Interest on long-term debt (2), (4)	2,781	2,723	58	-	-
Paid in kind interest on long-term debt (3)	22,133	22,133	-	-	-
Lease obligations	218	48	68	8	94
Total	$ 251,976	$ 249,543	$ 2,331	$ 8	$ 94

(1) These amounts represent the balances outstanding under our credit facilities and the real estate lien note. These payments assume that we will not borrow additional funds.

(2) Interest expense assumes the balances of long-term debt at December 31, and current effective interest rates at that time.

(3) Represents interest expense paid in kind on our Second Lien Credit Facility. Accrued interest was added to the outstanding balance and was payable at maturity.

(4) Our First Lien Credit Facility was retired, and our Second Lien Credit Facility was converted to Series A Preferred Stock on January 3, 2022, in connection with the restructuring and change in control that occurred on the same date.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2021, our reserve for these obligations totaled $4.7 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At December 31, 2021, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have, or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At December 31, 2021, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Long-Term Indebtedness.

Long-term debt consisted of the following:

	Years Ended December 31,	
	2020	2021
	(In thousands)	
First Lien Credit Facility	$ 95,000	$ 71,400
Second Lien Credit Facility	112,695	134,907
Exit fee - Second Lien Credit Facility	10,000	10,000
Real estate lien note	2,810	2,515
	220,505	218,822
Less current maturities	(202,751)	(212,688)
	17,754	6,134
Deferred financing fees and debt issuance cost - net	(15,239)	(3,929)
Total long-term debt, net of deferred financing fees and debt issuance costs	$ 2,515	$ 2,205

The following sections regarding the First Lien Credit Facility and Second Lien Credit Facility are qualified in their entirety by the disclosure contained in Item 1. Business, Recent Activity, which is expressly incorporated in the sections below. Due to certain covenant violations as of December 31, 2020, and the then-potential for future violations, all of the debt related to our credit facilities has been classified as current liabilities. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 “Subsequent Events.”

First Lien Credit Facility

Prior to January 3, 2022 the Company had a senior secured First Lien Credit Facility with Société Générale, as administrative agent and issuing lender, and certain other lenders. As of December 31, 2021, $71.4 million was outstanding under the First Lien Credit Facility.

Outstanding amounts under the First Lien Credit Facility accrued interest at a rate per annum equal to (a)(i) for borrowings that we elected to accrue interest at the reference rate at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the federal funds rate plus 0.5%, and (z) daily one-month LIBOR plus, in each case, 1.5%-2.5%, depending on the utilization of the borrowing base, and (ii) for borrowings that we elected to accrue interest at the Eurodollar rate, LIBOR plus 2.5%-3.5% depending on the utilization of the borrowing base, and (b) at any time an event of default existed, 3.0% plus the amounts set forth above. At December 31, 2021, the interest rate on the First Lien Credit Facility was approximately 8.75%.

Subject to earlier termination rights and events of default, the stated maturity date of the First Lien Credit Facility was May 16, 2022. Interest was payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company was permitted to terminate the First Lien Credit Facility and was able, from time to time, to permanently reduce the lenders’ aggregate commitment under the First Lien Credit Facility in compliance with certain notice and dollar increment requirements.

Each of the Company’s subsidiaries guaranteed our obligations under the First Lien Credit Facility on a senior secured basis. Obligations under the First Lien Credit Facility were secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors’ material property and assets. As of December 31, 2020, the collateral was required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company’s PDP reserves.

Under the amended First Lien Credit Facility, the Company was subject to customary covenants, including financial covenants and reporting covenants. The amendment to the First Lien Credit Facility dated June 25, 2020 (the “1L Amendment”) modified certain provisions of the First Lien Credit Facility, including (i) the addition of monthly mandatory prepayments from excess cash (defined as available cash minus certain cash set-asides and a $3.0 million working capital reserve) with corresponding reductions to the borrowing base; (ii) the elimination of scheduled redeterminations (which were previously made every six months) and interim redeterminations (which were previously made at the request of the lenders no more than once in the six month period between scheduled redeterminations) of the borrowing base; (iii) the replacement of total debt leverage ratio and minimum asset ratio covenants with a first lien debt leverage ratio covenant (comparing the outstanding debt of the First Lien Credit Facility to the consolidated EBITDAX of the Company and requiring that the ratio not exceed 2.75 to 1.00 as of the last day of each fiscal quarter) and a minimum first lien asset coverage ratio covenant (comparing the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company’s hydrocarbon hedge agreements and (C) the PV-15 of proved reserves of the Company classified as “drilled uncompleted” (up to 20% of the sum of (A), (B) and (C)) to the outstanding debt of the First Lien Credit Facility and requiring that the ratio exceed 1.15 to 1.00 as of the last day of each fiscal quarter ending on or before December 31, 2020, and 1.25 to 1.00 for fiscal quarters ending thereafter); (iv) the elimination of current ratio and interest coverage ratio covenants; (v) additional restrictions on (A) capital expenditures (limiting capital expenditures to $3.0 million in any four fiscal quarter period (commencing with the four fiscal quarter period ended June 30, 2020 and calculated on an annualized basis for the 1, 2 and 3 quarter periods ending on June 30, 2020, September 30, 2020 and December 31, 2020, respectively, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt and capital expenditures made when (1) the first lien asset coverage ratio is at least 1.60 to 1.00, (2) the Company is in compliance with the first lien leverage ratio, (3) the amounts outstanding under the First Lien Credit Facility are less $50.0 million, (4) no default exists under the First Lien Credit Facility and (5) and all representations and warranties in the First Lien Credit Facility and the related credit documents are true and correct in all material respects), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company could make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.9 million for the four fiscal quarter period ended December 31, 2020, and $6.5 million for the fiscal quarter from March 31, 2021 through December 31, 2021 and $5.0 million thereafter; in all cases, general and administrative expense excluded up to $1.0 million in certain legal and professional fees; and (vi) permission for up to an additional $25.0 million in structurally subordinated debt to finance capital expenditures. Under the 1L Amendment, the borrowing base was adjusted to $102.0 million. Prior to retirement, the borrowing base was reduced by any mandatory prepayments from excess cash flow.

As of December 31, 2021, we were not in compliance with the financial covenants under the First Lien Credit Facility, as amended. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

The First Lien Credit Facility contained a number of covenants that, among other things, restricted our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an " arm's length" basis;
- make any change in the principal nature of our business; and
- permit a change in control

The First Lien Credit Facility also contained customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Events of default occurred, or were reasonably likely to occur, under the First Lien Credit Facility as a result of (i) our failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) our inability to comply with the first lien debt to consolidated EBITDAX ratio for the fiscal quarter ended December 31, 2020, (iii) our failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the First Lien Credit Facility, and (iv) certain cross-defaults that have occurred, or could have occurred, as a result of the events of default under the First Lien Credit Agreement and corresponding cross-defaults under the Second Lien Credit Facility and cross-defaults or similar termination events under our hedging contracts.

Second Lien Credit Facility

On November 13, 2019, we entered into the Term Loan Credit Agreement, with Angelo Gordon Energy Servicer, LLC, as administrative agent, and certain other lenders party thereto, which we refer to as the Second Lien Credit Facility. The Second Lien Credit facility was amended on June 25, 2020. Prior to January 3, 2022, the Second Lien Credit Facility had a maximum commitment of $100.0 million. On November 13, 2019, $95.0 million of the net proceeds obtained from the Second Lien Credit Facility were used to permanently reduce the borrowings outstanding on the First Lien Credit Facility. As of December 31, 2021, the outstanding balance on the Second Lien Credit Facility was $144.9 million, which included a $10.0 million exit fee. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

The stated maturity date of the Second Lien Credit Facility was November 13, 2022. Prior to the latest amendments of the Second Lien Credit Facility, accrued interest was payable quarterly on reference rate loans and at the end of each three-month interest period on Eurodollar loans. We were permitted to prepay the loans in whole or in part, in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries had guaranteed our obligations under the Second Lien Credit Facility. Obligations under the Second Lien Credit Facility were secured by a first priority perfected security interest, subject to certain permitted liens, including those securing the indebtedness under the First Lien Credit Facility to the extent permitted by the Intercreditor Agreement, of even date with the Second Lien Credit Facility, among us, our subsidiaries, Angelo Gordon Energy Servicer, LLC and Société Générale, in all of our subsidiary guarantors' material property and assets. As of December 31, 2020, the collateral was required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company's PDP reserves.

Under the amended Second Lien Credit Facility, the Company was subject to customary covenants, including financial covenants and reporting covenants. The amendment to the Second Lien Credit Facility dated June 25, 2020 (the "2L Amendment") modified certain provisions of the Second Lien Credit Facility, including (i) a requirement that, while the obligations under the First Lien Credit Facility were outstanding, scheduled payments of accrued interest under the Second Lien Credit Facility would be paid in the form of capitalized interest; (ii) an increase in the interest rate by 200bps for interest payable in cash and 500bps for interest payable in kind; (iii) modification of the minimum asset ratio covenant to be the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedge agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the total outstanding debt of the Company and requiring that the ratio not exceed 1.45 to 1.00 as of the last day of each fiscal quarter ending between September 30, 2021 to December 31, 2021, and 1.55 to 1.00 for fiscal quarters ending thereafter); (iv) modification of the total leverage ratio covenant to set the first test date to occur on September 30, 2021; (v) modification of the then-current ratio to eliminate the exclusion of certain valuation accounts associated with hedge contracts from current assets and from current liabilities, (vi) additional restrictions on (A) capital expenditures (limiting capital expenditures to those expenditures set forth in a plan of development approved by Angelo Gordon Energy Servicer, LLC, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company could make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.5 million for fiscal quarter period from March 31, 2021 through December 31, 2021 and $5.0 million thereafter.

As of December 31, 2021, we were not in compliance with the financial covenants under the Second Lien Credit Facility, as amended. However, in connection with the restructuring that was completed on January 3, 2022 our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

The Second Lien Credit Facility contained a number of covenants that, among other things, restricted our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an "arm's length" basis;
- make any change in the principal nature of our business; and
- permit a change of control

The Second Lien Credit Facility also contained customary events of default, including nonpayment of principal or interest, violation of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Events of default occurred under the Second Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) the Company's failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the Second Lien Credit Facility, (iii) the failure of the Company to meet certain hedging requirements, (iv) the Company's inability to comply with the total leverage ratio for the fiscal quarter ended September 30, 2021, (v) the Company's inability to comply with minimum asset coverage ratio for the fiscal quarter ended September 30, 2021, and (vi) certain cross-defaults that occurred, or could have occurred, as a result of the occurrence of events of default under the First Lien Credit Facility and corresponding cross-defaults or similar termination events under our hedging contracts. Additional events of default occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended.

On April 16, 2021, we received a Notice of Default and Reservation of Rights (the "Notice of Default") from Angelo Gordon stating that we defaulted under the Second Lien Credit Facility, and that, as a result, the lenders accelerated our obligations due thereunder and reserved their rights to pursue additional remedies in the future.

The Notice of Default described certain events of default that occurred under the Second Lien Credit Facility as a result of (i) our failure to file timely our Form 10-K for the fiscal year ended December 31, 2020, (ii) our failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, and (iii) other defaults under our revolving credit facility.

The Notice of Default declared that our obligations under the Second Lien Credit Facility were immediately due and payable, in each case without presentment, demand, protest or other requirements of any kind, and began to bear interest at the rate applicable to such amount under the Second Lien Credit Facility, plus an additional 3%. Additionally, the administrative agent and the lenders reserved their right to exercise further rights, powers and remedies under the Second Lien Credit Facility, at any time or from time to time, with respect to any of the events of default described above.

In connection with the amendment to the Second Lien Credit Facility on June 25, 2020, the Company entered into an Exit Fee and Warrant Agreement subject to NASDAQ approval for the issuance of the issuance of certain warrants. This agreement was finalized on August 11, 2020 at which time the Company issued a warrant to the lender to purchase a total of 33,445,792 shares of common stock at an exercise price of $0.01 per share. On October 19, 2020, the Company effected a reverse stock split of the Company's authorized, issued and outstanding shares of common stock at a ratio of 1-for-20, thus the warrant was adjusted to provide that the lender may purchase a total of 1,672,290 shares of common stock at an exercise price of $0.20 per share. The warrant was exercisable immediately in whole or in part, on or before five years from the issuance date. The fair value of the warrant and exit fee were recorded as debt issuance costs, presented in the consolidated balance sheets as a deduction from the carrying amount of the note payable, and were being amortized over the loan term. The Exit Fee was due and payable in cash on the earliest to occur of maturity of the obligation under the Second Lien Credit Agreement or the earlier acceleration or payment in full of the same. The 2L Amendment, including the impact of the Exit Fee and Warrant Agreement finalized on August 11, 2020, resulted in the 2L Amendment meeting the criteria of debt extinguishment under the guidance of *ASC 470: Debt*. Accordingly, all debt issuance cost, including the original discount, of the original Second Lien Credit Facility, were charged to debt extinguishment loss in the accompanying Condensed Consolidated Statement of Operation in the amount of $4.1 million. Subsequently, pursuant to a waiver letter dated November 22, 2021 from AGEF to Abraxas, AGEF waived, relinquished, and abandoned all of its rights, title, and interest to the Warrant and any Common Stock underlying the Warrant for no consideration.

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The outstanding principal accrues interest at a fixed rate of 4.9%. The note is payable in monthly installments of principal and interest in the amount of $35,672. The maturity date of the note is July 20, 2023. As of December 31, 2020, and 2021, $2.8 million and $2.5 million, respectively, were outstanding on the note.

Net Operating Loss Carryforwards

At December 31, 2021, we had, subject to the limitation discussed below, $245.20 million of pre 2021 NOLs for U.S. tax purposes and a $190.8 million NOL for 2021. Our pre-2018 NOLs will expire in varying amounts from 2023 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising in 2018, 2019 and 2020 can generally be carried back five years, carried forward indefinitely and can offset 100% of future taxable income for tax years before January 1, 2021 and up to 80% of future taxable income for tax years after December 31, 2020. Any NOLs arising on or after January 1, 2021, cannot be carried back and can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes, (the alternative minimum tax no longer applies to corporations after January 1, 2018).

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10 "Income Taxes". Therefore, we have established a valuation allowance of $124.08 million for deferred tax assets at December 31, 2021.

Related Party Transactions

We have adopted a policy that transactions between us and our officers, directors, principal stockholders, or affiliates of any of them, will be on terms no less favorable to us than can be obtained on an arm's length basis in transactions with third parties and must be approved by our audit committee. There were no related party transactions in 2020 or 2021.

Critical Accounting Policies

The preparation of financial statements in conformity with U.S. generally accepted accounting principles ("GAAP") requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following represents those policies that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

Full Cost Method of Accounting for Oil and Gas Activities. SEC Regulation S-X Rule 4-10 and ASC 932 defines the financial accounting and reporting standards for companies engaged in oil and gas activities. Two methods are prescribed: the successful efforts method and the full cost method. We have chosen to follow the full cost method under which all costs associated with property acquisition, exploration and development are capitalized. We also capitalize internal costs that can be directly identified with our acquisition, exploration and development activities but do not include any costs related to production, general corporate overhead or similar activities. Sales of oil and gas properties are treated as a reduction of the full cost pool with no gain or loss being recognized, except under certain circumstances. Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion, amortization and impairment of oil and gas properties are generally calculated on a well by well or lease or field basis versus the "full cost" pool basis. Additionally, gain or loss may be recognized on sales of oil and gas properties under the successful efforts method. As a result, our financial statements will differ from those of companies that apply the successful efforts method since we will generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization rate on our oil and gas properties.

At the time it was adopted, management believed that the full cost method would be preferable, as earnings tend to be less volatile than under the successful efforts method. However, the full cost method makes us susceptible to significant non-cash charges during times of volatile commodity prices because the full cost pool may be impaired when prices are low. These charges are not recoverable when prices return to higher levels. We have experienced this situation several times over the years, including a $187.0 million impairment recorded as of December 31, 2020. Our oil and gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from impairment testing procedures associated with the full cost method of accounting as discussed below.

Under full cost accounting rules, the net capitalized cost of oil and gas properties, less related deferred taxes, may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves on a pool by pool basis, discounted at 10%, plus the lower of cost or fair market value of unproved properties and the cost of properties not being amortized, less income taxes. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flows from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and gas prices are depressed. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. Given the recent decline in oil prices, it is likely that we will incur future impairments.

Estimates of Proved Oil and Gas Reserves. Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved oil and gas reserves have been estimated by our independent petroleum engineering firm, DeGolyer & MacNaughton, as of December 31, 2020 and 2021, estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

You should not assume that the present value of future net cash flows is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on costs on the date of the estimate and for the years ended December 31, 2020 and 2021 oil and gas prices were based on the average 12-month first-day-of-the-month pricing. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate.

The estimates of proved reserves materially impact DD&A expense and the ceiling test calculation. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase and we may be required to record future impairments of the full cost pool, reducing future net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields.

Asset Retirement Obligations. The estimated costs of restoration and removal of facilities are accrued. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost is capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and we amortize these costs as a component of our depletion expense.

Accounting for Derivatives. Gains or losses are determined by actual derivative settlements during the period and on the periodic mark to market valuation of derivative contracts in place. The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. We have elected not to apply hedge accounting to our derivative contracts. As a result, fluctuations in the market value of the derivative contract are recognized in earnings during the current period. In 2020 and 2021 derivative contracts consisted of fixed price swaps and basis differential swaps. Due to the volatility of oil and gas prices, our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments. As of December 31, 2020, and 2021, the net market value of our commodity derivatives was a net asset of $ 19.4 million and a net liability of $0.4 million, respectively. All of the Company's derivative contracts were terminated or expired during 2021.

Recently Issued Accounting Standards

In March 2020, the FASB issued ASU No. 2020-04, "Reference Rate Reform (Topic 840): Facilitation of the Effects of Reference Rate Reform on Financial Reporting" ("ASU 2020-04"), which provides companies with optional guidance to ease the potential accounting burden associated with transitioning away from reference rates (e.g., London Interbank Offered Rate ("LIBOR")) that are expected to be discontinued. ASU 2020-04 allows, among other things, certain contract modifications, such as those within the scope of Topic 470 on debt, to be accounted as a continuation of the existing contract. This ASU was effective upon the issuance and its optional relief can be applied through December 31, 2022. The Company will consider this optional guidance prospectively, if applicable.

In May 2020, the SEC adopted final rules that amend the financial statement requirements for significant business acquisitions and dispositions. Among other changes, the final rules modify the significance tests and improve the disclosure requirements for acquired or to be acquired businesses and related pro forma financial information, the periods those financial statements must cover, and the form and content of the pro forma financial information. The final rules do not modify requirements for the acquisition and disposition of significant amounts of assets that do not constitute a business. The final rules are effective January 1, 2021, but earlier compliance is permitted. The Company will consider these final rules and update its disclosures, as applicable.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flows from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indices fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the year ended December 31, 2021, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flows by approximately $7.8 million for the year. If commodity prices remain at their current levels the impact on operating revenues and cash flows, could be much more significant. However, we do have derivative contracts in place that will mitigate the impact of low commodity prices.

Derivative Instrument Sensitivity

At December 31, 2021, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $0.4 million. The fair market value of our commodity derivative contracts is sensitive to changes in the market price for oil and gas. When our derivative contract prices are higher than prevailing market prices, we recognize gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur losses. As of December 31, 2021, we did not have any derivative contracts. The fair market value represents the December 2021 settlement, paid in January 2022.

Interest Rate Risk

We were subject to interest rate risk associated with borrowings under our First Lien Credit Facility and our Second Lien Credit facility. As of December 31, 2021, we had $71.4 million of outstanding indebtedness under our First Lien Credit Facility and $134.9 of outstanding indebtedness under our Second Lien Credit Facility, each with a variable interest rate. At December 31, 2021, the interest rate on the First Lien Credit Facility was approximately 8.75% . An increase in the interest rate of 1% would have increased our interest expense by $0.7 million on an annual basis, based on the outstanding balance at December 31, 2021. At December 31, 2021, the interest rate on the Second Lien Credit Facility was 18.75% . An increase of 1% would have increased our interest expense by $1.3 million on an annual basis, based on the outstanding balance at December 31, 2020. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

Item 8. Financial Statements and Supplementary Data

For the financial statements and supplementary data required by this Item 8, see the Index to Consolidated Financial Statements.

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

Under the supervision and with the participation of our management, including our Chief Executive Officer (our principal executive officer) and our Chief Financial Officer (our principal financial officer), we evaluated the effectiveness of our disclosure controls and procedures (as defined under Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on this evaluation, the Chief Executive Officer and our Chief Financial Officer concluded that disclosure controls and procedures as of December 31, 2021 were effective, as of the end of the reporting period covered by this report, our disclosure controls over financial reporting are effective.

Changes in Internal Controls

There were no changes in our internal control over financial reporting during the fourth quarter of 2021 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Company's principal executive and principal financial officers and implemented by the Company's 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 generally accepted accounting principles and includes those policies and procedures that: (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the

Treadway Commission. Based on our evaluation, our management concluded that our internal control over financial reporting was effective as of December 31, 2021.

The effectiveness of our internal control over financial reporting as of December 31, 2021 has not been audited.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

There is incorporated in this Item 10 by reference to that portion of our definitive proxy statement for the 2022 Annual Meeting of Stockholders which appears therein under the caption “Election of Directors – Board of Directors,” “– Code of Ethics,” “– Committees of the Board of Directors.” and Executive Officers.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2022 Annual Meeting of Stockholders which appears therein under the captions “Election of Directors – Committees of the Board of Directors” and “Executive Compensation.”

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

There is incorporated in this Item 12 by reference that portion of our definitive proxy statement for the 2022 Annual Meeting of Stockholders which appears therein under the captions “Securities Holdings of Principal Stockholders,” and “Securities Holdings of Directors, Nominees and Officers.”

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

There is incorporated in this Item 13 by reference that portion of our definitive proxy statement for the 2022 Annual Meeting of Stockholders which appears therein under the captions “Certain Relationships and Related Party Transactions” and “Election of Directors – Director Independence.”

Item 14. Principal Accountant Fees and Services

There is incorporated in this Item 14 by reference that portion of our definitive proxy statement for the 2022 Annual Meeting of Stockholders which appears therein under the caption “Principal Auditor Fees and Services.”

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)1. Consolidated Financial Statements

(a)2. Financial Statement Schedules

All schedules have been omitted because they are not required, not applicable, or the information required is included in the Consolidated Financial Statements or related notes thereto.

(a)3. Exhibits

The following Exhibits have previously been filed by the Registrant or are included following the Index to Exhibits.

Exhibit Number	Description
3.1	Articles of Incorporation of Abraxas dated August 30, 1990. (Filed as Exhibit 3.1 to our Registration Statement on Form S-4, No. 33-36565. (the "S-4 Registration Statement")).
3.2	Articles of Amendment to the Articles of Incorporation of Abraxas dated October 22, 1990. (Filed as Exhibit 3.3 to the S-4 Registration Statement).
3.3	Articles of Amendment to the Articles of Incorporation of Abraxas dated December 18, 1990. (Filed as Exhibit 3.4 to the S-4 Registration Statement).
3.4	Articles of Amendment to the Articles of Incorporation of Abraxas dated June 8, 1995. (Filed as Exhibit 3.4 to our Registration Statement on Form S-3, No. 333-00398).
3.5	Articles of Amendment to the Articles of Incorporation of Abraxas dated as of August 12, 2000. (Filed as Exhibit 3.5 to our Annual Report on Form 10-K filed on April 2, 2001).
3.6	Certificate of Correction dated February 24, 2011 (Filed as Exhibit 3.6 to our Annual Report on Form 10-K filed on March 15, 2012).
3.7	Certificate of Withdrawal dated March 16, 2015. (Filed as Exhibit 3.6 to our Current Report on Form 8-K filed March 17, 2015).
3.8	Certificate of Amendment to Articles of Incorporation dated May 9, 2017. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on May 10, 2017).
3.9	Certificate of Change Pursuant to NRS 78.209 dated October 19, 2020. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on October 16, 2020).

3.10 Certificate of Designation of Series A Preferred Stock dated January 3, 2022. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed January 3, 2022).

3.11 Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to our Current Report on Form 8-K filed on December 18, 2018).

3.12 Amendment to Bylaws of Abraxas dated January 3, 2022. (Filed as Exhibit 3.2 to our Current Report on Form 8-K filed January 3, 2022).

4.1 Specimen Common Stock Certificate of Abraxas. (Filed as Exhibit 4.1 to the S-4 Registration Statement).

4.2 Specimen Preferred Stock Certificate of Abraxas. (Filed as Exhibit 4.2 to our Annual Report on Form 10-K filed on March 31, 1995).

4.3 Certificate of Designation of Series A Preferred Stock dated January 3, 2022. (Filed as Exhibit 4.1 to our Current Report on Form 8-K filed January 3, 2022).

*10.1 Abraxas Petroleum Corporation 401(k) Profit Sharing Plan. (Filed as Exhibit 10.4 to our Registration Statement on Form S-4, No. 333-18673 filed on December 23, 1996).

*10.2 Form of Indemnity Agreement between Abraxas and each of its directors and officers. (Filed as Exhibit 10.4 to our Annual Report on Form 10-K filed March 14, 2007).

*10.3 Form of Employment Agreement for Executive Officers (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on December 18, 2018).

*10.5 Amended and Restated Abraxas Petroleum Corporation Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Appendix B to our Proxy Statement filed on April 2, 2015).

*10.6	Form of Stock Option Agreement under the Abraxas Petroleum Corporation Amended and Restated 2005 Non-Employee Directors Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to our Current Report on Form 8-K filed June 6, 2005).
*10.7	Abraxas Petroleum Corporation Senior Management Incentive Bonus Plan 2006. (Filed as Exhibit 10.17 to our Annual Report on Form 10-K filed March 23, 2006).
*10.8	Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Appendix A to our Proxy Statement filed on April 3, 2017).
*10.9	Form of Employee Stock Option Agreement under the Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to our Current Report on Form 8-K filed May 26, 2006).
*10.10	Form of Restricted Stock Agreement under the Amended and Restated Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan (Filed as Exhibit 10.1 to our Annual Report on Form 10-K filed on March 13, 2015).
*10.11	Form of Restricted Stock Award Agreement under Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.1 to our Current Report on Form 8-K filed on April 6, 2018).
10.12	Promissory Note dated November 13, 2008 by Abraxas Properties Incorporated and Abraxas Petroleum Corporation, payable to the order of Plains Capital Bank, as Lender. (Filed as Exhibit 10.1 to our Current Report on Form 10-Q filed on August 8, 2014.)
10.13	Second Modification, Renewal and Extension of Promissory Note and Deed of Trust Liens by and between Plains Capital Bank, Abraxas Properties Corporation and Abraxas Petroleum Corporation effective March 13, 2013. (Previously filed as Exhibit 10.2 to our Current Report on Form 10-Q filed on August 8, 2014).
10.14	Third Modification, Renewal and Extension of Promissory Note and Deed of Trust Liens by and between Plains Capital Bank, Abraxas Properties Incorporated and Abraxas Petroleum Corporation effective as of July 13, 2013. (Previously filed as Exhibit 10.3 to our Current Report on Form 10-Q filed on August 8, 2014).

14.1	Abraxas Petroleum Corporation Code of Business Conduct and Ethics. (Filed as Exhibit 14.1 to our Annual Report on Form 10-K filed March 22, 2006).
21.1	Subsidiaries of Abraxas. (Previously filed as Exhibit 21.1 to our Annual Report on Form 10-K filed on March 15, 2016).
23.1	Consent of ADKF PC (Filed herewith).
23.2	Consent of DeGolyer and MacNaughton. (Filed herewith)
31.1	Certification – Chief Executive Officer. (Filed herewith).
31.2	Certification – Chief Financial Officer. (Filed herewith).
32.1	Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).
32.2	Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).
99.1	DeGolyer and MacNaughton's report with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).
101.INS	Inline XBRL Instance Document (the Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)
*	Management Compensatory Plan or Agreement.

Item 16. 10-K Summary

None

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Abraxas Petroleum Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Abraxas Petroleum Corporation (the Company) as of December 31, 2021 and 2020, and the related consolidated statements of operations, stockholders' equity, and cash flows for the years then ended, and the related notes (collectively referred to as the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures 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 consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was 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. Communication of the critical audit matter 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of estimated oil and gas reserves related to proved oil and gas properties on depletion expense and the ceiling test calculation

The Company calculates depletion expense for its proved oil and gas properties using the units-of-production method whereby capitalized costs, including estimated future development costs and asset retirement costs, are amortized over total estimated proved reserves. Additionally, the Company is required to perform a ceiling test calculation on a quarterly basis to evaluate impairment of its proved oil and gas properties. For the year ended December 31, 2021, the Company recorded depletion expense related to proved oil and gas properties of $15.3 million.

We identified the impact of the estimate of proved oil and gas reserves used in the determination of depletion expense and the ceiling test calculation as a critical audit matter. There is a high degree of subjectivity in evaluating the estimate of proved oil and gas reserves as auditor judgment was required to evaluate the assumptions used by the Company related to forecasts of production, future operating costs and future development costs, and oil and gas prices inclusive of market differentials.

To address this critical audit matter we performed the following procedures. (1) We evaluated the level of knowledge, skill, and ability of the Company's reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's specialists. (2) To the extent key, sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, such as historical pricing differentials, operating costs, estimated capital costs and working and net revenue interests, we tested management's process for determining the assumptions, including examining the underlying support, on a sample basis.

/s/ ADKF, P.C.

We have served as the Company's auditor since 2020.

San Antonio, Texas
March 31, 2022

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ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

ASSETS

	December 31,	
	2020	2021
	(In thousands, except per share/ share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 2,775	$ 10,034
Accounts receivable:		
Joint owners, net	1,255	1,117
Oil and gas production sales	8,794	12,280
Other	-	150
Total accounts receivable	10,049	13,547
Derivative asset - short-term	9,639	-
Other current assets	1,588	498
Total current assets	24,051	24,079
Property and equipment		
Proved oil and gas properties, full cost method	1,167,333	1,165,707
Other property and equipment	39,456	39,337
Total	1,206,789	1,205,044
Less accumulated depreciation, depletion, amortization and impairment	(1,083,843)	(1,099,075)
Total property and equipment - net	122,946	105,969
Operating lease right-of-use assets	228	173
Derivative asset - long term	10,281	-
Other assets	255	255
Total assets	$ 157,761	$ 130,476

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS (CONTINUED)

LIABILITIES AND STOCKHOLDERS' EQUITY

	December 31,	
	2020	**2021**
	(In thousands)	
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 6,074	$ 4,678
Joint interest oil and gas production payable	8,795	13,347
Accrued interest	86	477
Other accrued liabilities	230	347
Derivative liabilities - short-term	480	442
Termination of derivative contracts	-	8,022
Right of use liability	53	40
Current maturities of long-term debt	202,751	212,688
Other current liabilities	850	-
Total current liabilities	219,319	240,041
Long-term debt - less current maturities	2,515	2,205
Paycheck protection program loan	1,384	-
Right of use liability	150	110
Future site restoration	7,360	4,708
Total liabilities	230,728	247,064
Commitments and contingencies (Note 8)		
Stockholders' Deficit		
Preferred stock, par value $0.01 per share - authorized 1,000,000 shares; - 0- shares issued and outstanding	-	-
Common stock, par value $0.01 per share, authorized 20,000,000 shares; 8,421,910 issued and outstanding at December 31, 2020 and 2021	84	84
Additional paid-in capital	429,476	430,422
Accumulated deficit	(502,527)	(547,094)
Total stockholders' deficit	(72,967)	(116,588)
Total liabilities and stockholders' deficit	$ 157,761	$ 130,476

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31, 2020	2021
	(In thousands, except per share data)	
Revenues:		
Oil	$ 41,969	$ 61,228
Gas	586	8,656
Natural gas liquids	429	8,952
Other	59	22
Total Revenue	43,043	78,858
Operating costs and expenses		
Lease operating	16,458	17,914
Production and ad valorem taxes	4,632	6,223
Rig expense	762	478
Depreciation, depletion, amortization and accretion	24,846	15,643
Proved property impairment	186,980	-
General and administrative (including stock-based compensation of $946 and $1,312, respectively)	8,783	8,116
Total operating costs and expenses	242,461	48,374
Operating (loss) income	(199,418)	30,484
Other (income) expense:		
Interest income	(39)	(15)
Interest expense	21,281	35,773
Amortization of deferred financing fees	2,565	4,804
Deferred finance fees and warrant cancelation	-	4,212
Gain on debt extinguishment (PPP loan)	-	(2,716)
Loss on debt extinguishment	4,108	-
(Gain) loss on derivative contracts	(42,880)	33,022
Gain on sale of non-oil and gas assets	-	(29)
Other	69	-
Total other (income) expense	(14,896)	75,051
(Loss) before income tax	(184,522)	(44,567)
Income tax (expense) benefit	-	-
Net loss	$ (184,522)	$ (44,567)
Net loss per common share - basic	$ (22.01)	$ (5.30)
Net loss per common share - diluted	$ (22.01)	$ (5.30)
Weighted average shares outstanding		
Basic	8,382	8,408
Diluted	8,382	8,408

See accompanying notes to consolidated financial statements.

ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands except number of shares)

	Common Stock Shares	Common Stock Amount	Additional Paid in Capital	Accumulated Deficit	Total
Balance at December 31, 2019	8,436,498	$ 84	$ 421,740	$ (318,005)	$ 103,819
Net loss	-	-	-	(184,522)	(184,522)
Warrant issued	-	-	6,424	-	6,424
Stock-based compensation	-	-	1,312	-	1,312
Restricted stock issued, net of forfeitures	(14,588)	-	-	-	-
Balance at December 31, 2020	8,421,910	84	429,476	(502,527)	(72,967)
Net loss		-		(44,567)	(44,567)
Stock-based compensation	-	-	946	-	946
Balance at December 31, 2021	8,421,910	$ 84	$ 430,422	$ (547,094)	$ (116,588)

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31,	
	2020	2021
Operating Activities:		
Net loss	$ (184,522)	$ (44,567)
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Loss (gain) on sale of non-oil and gas assets	-	(29)
Net loss (gain) on derivative contracts	(42,880)	33,022
Net cash settlements received (paid) on derivative contracts	16,006	(3,197)
Depreciation, depletion and amortization	24,432	15,312
Proved property impairment	186,980	-
Amortization of deferred financing fees and issuance discount	3,926	8,781
Non-cash financing fees and warrant cancellation	-	194
Accretion of future site restoration	414	330
Loss on debt extinguishment	4,108	-
Debt forgiveness PPP loan	-	(2,716)
Plugging cost	(236)	(342)
Non-cash interest	12,695	24,705
Non-cash hedge termination	-	9,943
Stock-based compensation	1,312	946
Changes in operating assets and liabilities:		
Accounts receivable	9,596	(3,498)
Other assets	(394)	(8,851)
Accounts payable	(15,304)	3,151
Accrued expenses and other	(148)	(765)
Net cash provided by operating activities	15,985	32,419
Investing Activities		
Capital expenditures, including purchase and development of properties	(12,557)	(887)
Proceeds from the sale of oil and gas properties	-	141
Proceeds from the sale of non-oil and gas assets	-	228
Net cash (used) in investing activities	(12,557)	(518)
Financing Activities		
Proceeds from long-term borrowings - First Lien Credit Facility	8,000	-
Proceeds from PPP loan	1,384	1,332
Payments of long-term borrowings	(9,059)	(25,816)
Deferred financing fees	(978)	(158)
Net cash (used) in financing activities	(653)	(24,642)
Increase in cash and cash equivalents	2,775	7,259
Cash and cash equivalents at beginning of period	-	2,775
Cash and cash equivalents at end of period	$ 2,775	$ 10,034
Supplemental disclosure of cash flow information:		
Interest paid	$ 7,174	$ 6,463
Income tax paid	$ -	$ -
Non-cash investing and financing activities		

Change in asset retirement obligation cost and liabilities	$	(22)	$	204
Asset retirement obligations associated with dispositions	$	(216)	$	(2,845)
Change in capital expenditures included in accounts payable	$	(7,157)	$	5

See accompanying notes to consolidated financial statements.

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ABRAXAS PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Significant Accounting Policies

Nature of Operations

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States. Our oil and gas assets are located primarily in two operating regions in the United States: the Rocky Mountains and Permian/Delaware Basin.

The terms “Abraxas,” “Abraxas Petroleum,” “we,” “us,” “our” or the “Company” refer to Abraxas Petroleum Corporation and all of its subsidiaries, including Raven Drilling LLC (“Raven Drilling”).

Rig Accounting

In accordance with SEC Regulation S-X, no income is recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates holds an ownership, or other economic interest. Any income not recognized as a result of this limitation is credited to the full cost pool and recognized through lower amortization as reserves are produced. During 2020 and 2021 the drilling rig was idle, accordingly the cost of the rig was charged to the statement of operations.

Use of Estimates

The consolidated financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in the United States of America (“GAAP”). The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The most significant estimates pertain to proved oil, gas and NGL reserves and related cash flow estimates used in impairment tests of oil and gas properties, the fair value of assets and liabilities acquired in business combinations, derivative contracts, the provision for income taxes including uncertain tax positions, stock based compensation, asset retirement obligations, accrued oil and gas revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, differentials, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, our ability to fund estimated development cost, prevailing oil and gas prices and other factors, many of which are beyond our control.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform to the current period presentation. These reclassifications were to share and per share data related to the 1 for 20 reverse stock split effective October 19, 2020 and had no effect on our previously reported results of operations.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables and derivative contracts. Accounts receivable are generally from companies with significant oil and gas marketing or operating activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers. The counterparties to our derivative contracts are the same financial institutions from which we have outstanding debt; accordingly, we believe our exposure to credit risk to these counterparties is currently mitigated in part by this, as well as the current overall financial condition of the counterparties.

The Company maintains any cash and cash equivalents in excess of federally insured limits in prominent financial institutions considered by the Company to be of high credit quality.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits and short-term investments with original maturities of three months or less.

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $0.1 million at December 31, 2020 and 2021 . The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of oil and gas with all of the Company's operational activities being conducted in the U.S. The Company's current operational activities and the Company's consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long lived assets located outside the U.S.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, certain direct costs and indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated future net revenues are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. The Company applies the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. The impairment calculations do not consider the impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. As of December 31, 2020, our capitalized cost of oil and gas properties exceeded the future net revenue from our estimated proved reserves resulting in the recognition of an impairment of $187.0 million. As of December 31, 2021, our capitalized cost of oil and gas properties did not exceed the future net revenue from our estimated proved reserves.

Other Property and Equipment

Other property and equipment are recorded at cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and improvements are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

Estimates of Proved Oil and Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved reserve information included in this report was based on studies performed by our independent petroleum engineers assisted by the engineering and operations departments of Abraxas. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may cause material revisions to the estimate.

In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on the average of oil and gas prices based on the unweighted average 12 month first-day-of-month pricing. Future prices and costs may be materially higher or lower than these prices and costs which would impact the estimated value of our reserves.

The estimates of proved reserves materially impact depreciation, depletion and amortization, or DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields.

Derivative Instruments and Hedging Activities

The Company enters into agreements to hedge the risk of future oil and gas price fluctuations. Such agreements are typically in the form of fixed price commodity and basis swaps, which limit the impact of price fluctuations with respect to the Company's sale of oil and gas. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions could arise where actual production is less than estimated which could result in over hedged volumes.

All derivative instruments are recorded on the Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The derivative instruments the Company utilizes are based on index prices that may and often do differ from the actual oil and gas prices realized in its operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for hedge accounting rules as prescribed by Accounting Standards Codification ("ASC") 815. Accordingly, the Company does not account for its derivative instruments as cash flow hedges for financial reporting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in net gains (losses) on commodity derivative contracts in the Consolidated Statements of Operations.

Fair Value of Financial Instruments

The Company includes fair value information in the notes to consolidated financial statements when the fair value of its financial instruments is materially different from the carrying value. The carrying value of those financial instruments that are classified as current, except for derivative instruments, approximates fair value because of the short maturity of these instruments. For noncurrent financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments.

Share-Based Payments

Options granted are valued at the date of grant and expense is recognized over the vesting period. The Company currently utilizes a standard option pricing model (Black-Scholes) to measure the fair value of stock options granted to employees and directors. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such restricted stock is determined using the market price on the grant date and expense is recorded over the vesting period. For the years ended December 31, 2020 and 2021, stock-based compensation was approximately $1.3 million and $0.9 million, respectively.

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and we amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements. Each year, the Company reviews, and to the extent necessary, revises its asset retirement obligation estimates.

The following table (in thousands) summarizes changes in the Company's future site restoration obligations during the two years ended December 31:

	2020	2021
Beginning future site restoration obligation	$ 7,420	$ 7,360
New wells placed on production and other	43	1
Deletions related to property disposals	(216)	(2,845)
Deletions related to plugging costs	(235)	(342)
Accretion expense and other	414	330
Revisions and other	(66)	204
Ending future site restoration obligation	$ 7,360	$ 4,708

Revenue Recognition and Major Purchasers

The Company recognizes oil and gas revenue from its interest in producing wells as oil and gas is sold from those wells, net of royalties, control of the product has transferred to the purchaser and collectability is reasonably assured.

During 2020 four purchasers accounted for 73% of oil and gas revenues. During 2021, four purchasers accounted for 83% of oil and gas revenues.

Deferred Financing Fees

Deferred financing fees are being amortized on the effective yield basis over the term of the related debt.

Income Taxes

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to be in effect with respect to taxable income in the years in which those temporary differences are expected to be recovered or settled. Uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, we have established a valuation allowance of $124.08 million for deferred tax assets at December 31, 2021.

Accounting for Uncertainty in Income Taxes

Evaluation of a tax position is a two-step process. The first step is to determine whether it is more-likely-than-not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation based on the technical merits of that position. The second step is to measure a tax position that meets the more-likely-than-not threshold to determine the amount of benefit to be recognized in the financial statements. A tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

Tax positions that previously failed to meet the more-likely-than-not recognition threshold should be recognized in the first subsequent period in which the threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not criteria should be de-recognized in the first subsequent reporting period in which the threshold is no longer met. Penalties and interest are classified as income tax expense. The Company had no uncertain income tax positions as of December 31, 2021.

Adoption of New Accounting Standards

In March 2020, the FASB issued ASU No. 2020-04, “Reference Rate Reform (Topic 840): Facilitation of the Effects of Reference Rate Reform on Financial Reporting” (“ASU 2020-04”), which provides companies with optional guidance to ease the potential accounting burden associated with transitioning away from reference rates (e.g., London Interbank Offered Rate (“LIBOR”)) that are expected to be discontinued. ASU 2020-04 allows, among other things, certain contract modifications, such as those within the scope of Topic 470 on debt, to be accounted as a continuation of the existing contract. This ASU was effective upon the issuance and its optional relief can be applied through December 31, 2022. The Company will consider this optional guidance prospectively, if applicable.

In May 2020, the SEC adopted final rules that amend the financial statement requirements for significant business acquisitions and dispositions. Among other changes, the final rules modify the significance tests and improve the disclosure requirements for acquired or to be acquired businesses and related pro forma financial information, the periods those financial statements must cover, and the form and content of the pro forma financial information. The final rules do not modify requirements for the acquisition and disposition of significant amounts of assets that do not constitute a business. The final rules are effective January 1, 2021, but earlier compliance is permitted. The Company will consider these final rules and update its disclosures, as applicable.

2. Revenue from Contracts with Customers

Revenue Recognition

Sales of oil, gas and NGL are recognized at the point in time when control of the product is transferred to the customer and collectability is reasonably assured. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, physical location, quality of the oil or gas, and prevailing supply and demand conditions. As a result, the price of the oil, gas and NGL fluctuates to remain competitive with other available oil, gas and NGL supplies in the market. The Company believes that the pricing provisions of our oil, gas and NGL contracts are customary in the industry.

Oil sales

The Company's oil sales contracts are generally structured such that it sells its oil production to a purchaser at a contractually specified delivery point at or near the wellhead. The crude oil production is priced on the delivery date based upon prevailing index prices less certain deductions related to oil quality, physical location and transportation costs incurred by the purchaser subsequent to delivery. The Company recognizes revenue when control transfers to the purchaser upon delivery at or near the wellhead at the net price received from the purchaser. Payment terms as customarily and normally paid on the twentieth day of the month following production.

Gas and NGL Sales

Under the Company's gas processing contracts, it delivers wet gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. There are no performance obligations related to these contracts. The midstream processing entity processes the gas and remits proceeds to the Company based upon either (i) the resulting sales price of NGL and residue gas received by the midstream processing entity from third party customers or (ii) the prevailing index prices for NGL and residue gas in the month of delivery to the midstream processing entity. Gathering, processing, transportation and other expenses incurred by the midstream processing entity are typically deducted from the proceeds that the Company receives.

In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. With respect to the Company's gas purchase contracts, the Company has concluded that it is the agent, and thus, the midstream processing entity is its customer. Accordingly, the Company recognizes revenue upon delivery to the midstream processing entity based on the net amount of the proceeds received from the midstream processing entity.

Imbalances

The Company had no material gas imbalances at December 31, 2020 and 2021.

Disaggregation of Revenue

The Company is focused on the development of oil and natural gas properties primarily located in the following operating regions in the United States: (i) the Permian/Delaware Basin and (ii) Rocky Mountain. Revenue attributable to each of those regions is disaggregated in the table below.

	Years Ended December 31,					
	2020			2021		
	Oil	Gas	NGL	Oil	Gas	NGL
Operating Region						
Permian/Delaware Basin	$ 22,891	$ 335	$ 163	$ 32,666	$ 4,474	$ 2,181
Rocky Mountain (1)	$ 19,078	$ 251	$ 266	$ 28,562	$ 4,182	$ 6,771

(1) All Rocky Mountain assets were sold January 3, 2022.

Significant Judgments

Principal versus agent

The Company engages in various types of transactions in which midstream entities process the Company's gas and subsequently market resulting NGL and residue gas to third-party customers on behalf of the Company, such as the Company’s percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

Transaction price allocated to remaining performance obligations

A significant number of the Company’s product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC Topic 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606-10-50-14(a) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under the Company’s product sales contracts, the Company is entitled to payment from purchasers once its performance obligations have been satisfied upon delivery of the product, at which point payment is unconditional. The Company records invoiced amounts as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheet.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and also recorded as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheets. In this scenario, payment is also unconditional, as the Company has satisfied its performance obligations through delivery of the relevant product. As a result, the Company has concluded that its product sales do not give rise to contract assets or liabilities under ASU 2014-09. At December 31, 2020 and December 31, 2021, our receivables from contracts with customers were $8.8 million and $12.3 million, respectively.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGL sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the midstream purchaser and the price that will be received for the sale of the product. Additionally, to the extent actual volumes and prices of oil are unavailable for a given reporting period because of timing or information not received from third party purchasers, the expected sales volumes and prices for those barrels of oil are also estimated.

The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the year ended December 31, 2021, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

3. Reverse Stock Split

On October 19, 2020 the Company effected a 1-for-20 reverse stock split of its issued and outstanding shares of common stock, $0.01 par value (the “ Reverse Stock Split”). The Company effected the Reverse Stock Split pursuant to the Company’s filing of a Certificate of Change with the Secretary of State of the State of Nevada on September 29, 2020. Under Nevada law, no amendment to the Company’s Articles of Incorporation was required in connection with the Reverse Stock Split. The Company was authorized to issue 400,000,000 shares of Common Stock. As a result of the Reverse Stock Split, the Company will be authorized to issue 20,000,000 shares of Common Stock. As a result of the Reverse Stock Split, 168,069,305 outstanding shares of the Company's common stock were exchanged for approximately 8,453,466 shares of the Company's common stock (subject to adjustment due to the effect of rounding fractional shares into whole shares). Under the terms of the Reverse Stock Split, fractional shares issuable to stockholders were rounded up to the nearest whole share. The Reverse Stock Split will not have any effect on the stated par value of the Common Stock. All per share amounts and number of shares in the condensed consolidated financial statements and related notes have been retroactively restated to reflect the Reverse Stock Split, resulting in the transfer of $1.6 million from common stock to additional paid in capital at September 30, 2020 and December 31, 2019.

Additionally on the effective date of the Reverse Stock Split, all options, warrants and other convertible securities of the Company outstanding immediately prior to the Reverse Stock Split were adjusted by dividing the number of shares of common stock into which the options, warrants and other convertible securities are exercisable or convertible by 20, and multiplying the exercise or conversion price thereof by 20, all in accordance with the terms of the plans, agreements or arrangements governing such options, warrants and other convertible securities and subject to rounding to the nearest whole share.

4. Long-Term Debt

The following sections regarding the First Lien Credit Facility and Second Lien Credit Facility are qualified in their entirety by the disclosure contained in Note 14. "Subsequent Events", Restructuring, which is expressly incorporated in the sections above. Due to certain of covenant violations under our credit facilities as of December 31, 2020 and 2021, all of the debt related to our credit facilities has been classified as current liabilities. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

The following is a description of the Company's debt as of December 31, 2020 and 2021, respectively:

	Years Ended December 31, 2020	Years Ended December 31, 2021
	(In thousands)	
First Lien Credit Facility	$ 95,000	$ 71,400
Second Lien Credit Facility	112,695	134,907
Exit fee - Second Lien Credit Facility	10,000	10,000
Real estate lien note	2,810	2,515
	220,505	218,822
Less current maturities	(202,751)	(212,688)
	17,754	6,134
Deferred financing fees and debt issuance cost - net	(15,239)	(3,929)
Total long-term debt, net of deferred financing fees and debt issuance costs	$ 2,515	$ 2,205

Maturities of long-term debt are as follows:

Years ending December 31, (In thousands)	
2022	$ 216,617
2023	2,205
2024	
2025	-
2026	-
Thereafter	-
Total	$ 218,822

First Lien Credit Facility

The Company had a senior secured First Lien Credit Facility with Société Générale, as administrative agent and issuing lender, and certain other lenders. As of December 31, 2021, $71.4 million was outstanding under the First Lien Credit Facility.

Outstanding amounts under the First Lien Credit Facility accrued interest at a rate per annum equal to (a)(i) for borrowings that we elected to accrue interest at the reference rate at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the federal funds rate plus 0.5%, and (z) daily one-month LIBOR plus, in each case, 1.5%-2.5%, depending on the utilization of the borrowing base, and (ii) for borrowings that we elected to accrue interest at the Eurodollar rate, LIBOR plus 2.5%-3.5% depending on the utilization of the borrowing base, and (b) at any time an event of default existed, 3.0% plus the amounts set forth above. At December 31, 2021, the interest rate on the First Lien Credit Facility was approximately 8.75%.

Subject to earlier termination rights and events of default, the stated maturity date of the First Lien Credit Facility was May 16, 2022. Interest was payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company was permitted to terminate the First Lien Credit Facility and was able, from time to time, to permanently reduce the lenders' aggregate commitment under the First Lien Credit Facility in compliance with certain notice and dollar increment requirements.

Each of the Company's subsidiaries guaranteed our obligations under the First Lien Credit Facility on a senior secured basis. Obligations under the First Lien Credit Facility were secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors' material property and assets. As of December 30, 2020, the collateral was required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company's PDP reserves.

Under the amended First Lien Credit Facility, the Company was subject to customary covenants, including financial covenants and reporting covenants. The amendment to the First Lien Credit Facility dated June 25, 2020 (the "1L Amendment") modified certain provisions of the First Lien Credit Facility, including (i) the addition of monthly mandatory prepayments from excess cash (defined as available cash minus certain cash set-asides and a $3.0 million working capital reserve) with corresponding reductions to the borrowing base; (ii) the elimination of scheduled redeterminations (which were previously made every six months) and interim redeterminations (which were previously made at the request of the lenders no more than once in the six month period between scheduled redeterminations) of the borrowing base; (iii) the replacement of total debt leverage ratio and minimum asset ratio covenants with a first lien debt leverage ratio covenant (comparing the outstanding debt of the First Lien Credit Facility to the consolidated EBITDAX of the Company and requiring that the ratio not exceed 2.75 to 1.00 as of the last day of each fiscal quarter) and a minimum first lien asset coverage ratio covenant (comparing the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedge agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the outstanding debt of the First Lien Credit Facility and requiring that the ratio exceed 1.15 to 1.00 as of the last day of each fiscal quarter ending on or before December 31, 2020, and 1.25 to 1.00 for fiscal quarters ending thereafter); (iv) the elimination of current ratio and interest coverage ratio covenants; (v) additional restrictions on (A) capital expenditures (limiting capital expenditures to $3.0 million in any four fiscal quarter period (commencing with the four fiscal quarter period ended June 30, 2020 and calculated on an annualized basis for the 1, 2 and 3 quarter periods ended on June 30, 2020, September 30, 2020 and December 31, 2020, respectively, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt and capital expenditures made when (1) the first lien asset coverage ratio is at least 1.60 to 1.00, (2) the Company is in compliance with the first lien leverage ratio, (3) the amounts outstanding under the First Lien Credit Facility are less $50.0 million, (4) no default exists under the First Lien Credit Facility and (5) and all representations and warranties in the First Lien Credit Facility and the related credit documents are true and correct in all material respects), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company may make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.9 million for the four fiscal quarter period ended December 31, 2020, and $6.5 million for the fiscal quarter from March 31, 2021 through December 31, 2021 and $5.0 million thereafter; in all cases, general and administrative expense excluded up to $1.0 million in certain legal and professional fees; and (vi) permission for up to an additional $25.0 million in structurally subordinated debt to finance capital expenditures. Under the 1L Amendment, the borrowing base was adjusted to $102.0 million. Prior to retirement, the borrowing base was reduced by any mandatory prepayments from excess cash flow.

The First Lien Credit Facility contained a number of covenants that, among other things, restricted our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an “arm’s length” basis;
- make any change in the principal nature of our business; and
- permit a change in control

The First Lien Credit Facility also contained customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

As of December 31, 2021, we were not in compliance with the financial covenants under the First Lien Credit Facility, as amended.

In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 “Subsequent Events.”

Second Lien Credit Facility

On November 13, 2019, we entered into the Term Loan Credit Agreement, with Angelo Gordon Energy Servicer, LLC, as administrative agent, and certain other lenders party thereto, which we refer to as the Second Lien Credit Facility. The Second Lien Credit facility was amended on June 25, 2020. The Second Lien Credit Facility had a maximum commitment of $100.0 million. On November 13, 2019, $95.0 million of the net proceeds obtained from the Second Lien Credit Facility were used to permanently reduce the borrowings outstanding on the First Lien Credit Facility. As of December 31, 2021, the outstanding balance on the Second Lien Credit Facility was $144.9 million, which included a $10.0 million exit fee. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 “Subsequent Events.”

The stated maturity date of the Second Lien Credit Facility was November 13, 2022. Prior to the latest amendments of the Second Lien Credit Facility, accrued interest was payable quarterly on reference rate loans and at the end of each three-month interest period on Eurodollar loans. We were permitted to prepay the loans in whole or in part, in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries had guaranteed our obligations under the Second Lien Credit Facility. Obligations under the Second Lien Credit Facility were secured by a first priority perfected security interest, subject to certain permitted liens, including those securing the indebtedness under the First Lien Credit Facility to the extent permitted by the Intercreditor Agreement, of even date with the Second Lien Credit Facility, among us, our subsidiaries, Angelo Gordon Energy Servicer, LLC and Société Générale, in all of our subsidiary guarantors’ material property and assets. As of December 31, 2020, the collateral was required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company’s PDP reserves.

Under the amended Second Lien Credit Facility, the Company was subject to customary covenants, including financial covenants and reporting covenants. The amendment to the Second Lien Credit Facility dated June 25, 2020 (the "2L Amendment") modified certain provisions of the Second Lien Credit Facility, including (i) a requirement that, while the obligations under the First Lien Credit Facility were outstanding, scheduled payments of accrued interest under the Second Lien Credit Facility would be paid in the form of capitalized interest; (ii) an increase in the interest rate by 200bps for interest payable in cash and 500bps for interest payable in kind; (iii) modification of the minimum asset ratio covenant to be the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedge agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the total outstanding debt of the Company and requiring that the ratio not exceed 1.45 to 1.00 as of the last day of each fiscal quarter ending between September 30, 2021 to December 31, 2021, and 1.55 to 1.00 for fiscal quarters ending thereafter); (iv) modification of the total leverage ratio covenant to set the first test date to occur on September 30, 2021; (v) modification of the current ratio to eliminate the exclusion of certain valuation accounts associated with hedge contracts from current assets and from current liabilities, (vi) additional restrictions on (A) capital expenditures (limiting capital expenditures to those expenditures set forth in a plan of development approved by Angelo Gordon Energy Servicer, LLC, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company could make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.5 million for fiscal quarter period from March 31, 2021 through December 31, 2021 and $5.0 million thereafter.

The Second Lien Credit Facility contained a number of covenants that, among other things, restricted our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an "arm's length" basis;
- make any change in the principal nature of our business; and
- permit a change of control

The Second Lien Credit Facility also contained customary events of default, including nonpayment of principal or interest, violation of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Events of default occurred under the Second Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the Second Lien Credit Facility, (iii) the failure of the Company to meet certain hedging requirements, (iv) the Company's inability to comply with the total leverage ratio for the fiscal quarter ended September 30, 2021, (v) the Company's inability to comply with minimum asset coverage ratio for the fiscal quarter ended September 30, 2021, and (vi) certain cross-defaults that occurred, or could have occurred, as a result of the occurrence of events of default under the First Lien Credit Facility and corresponding cross-defaults or similar termination events under our hedging contracts. Additional events of default occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended.

On April 16, 2021, we received a Notice of Default and Reservation of Rights (the "Notice of Default") from Angelo Gordon stating that we defaulted under the Second Lien Credit Facility, and that, as a result, the lenders accelerated our obligations due thereunder and reserved their rights to pursue additional remedies in the future.

The Notice of Default described certain events of default that occurred under the Second Lien Credit Facility as a result of (i) our failure to file timely our Form 10-K for the fiscal year ended December 31, 2020, (ii) our failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, and (iii) other defaults under our revolving credit facility.

The Notice of Default declared that our obligations under the Second Lien Credit Facility are immediately due and payable, in each case without presentment, demand, protest or other requirements of any kind, and began to bear interest at the rate applicable to such amount under the Second Lien Credit Facility, plus an additional 3%. Additionally, the administrative agent and the lenders reserved their right to exercise further rights, powers and remedies under the Second Lien Credit Facility, at any time or from time to time, with respect to any of the events of default described above.

In connection with the amendment to the Second Lien Credit Facility on June 25, 2020, the Company entered into an Exit Fee and Warrant Agreement subject to NASDAQ approval for the issuance of the issuance of certain warrants. This agreement was finalized on August 11, 2020 at which time the Company issued a warrant to the lender to purchase a total of 33,445,792 shares of common stock at an exercise price of $0.01 per share. On October 19, 2020, the Company effected a reverse stock split of the Company's authorized, issued and outstanding shares of common stock at a ratio of 1-for-20, thus the warrant was adjusted to provide that the lender may purchase a total of 1,672,290 shares of common stock at an exercise price of $0.20 per share. The warrant was exercisable immediately in whole or in part, on or before five years from the issuance date. The fair value of the warrant and exit fee were recorded as debt issuance costs, presented in the consolidated balance sheets as a deduction from the carrying amount of the note payable, and were being amortized over the loan term. The exit fee was due and payable in cash on the earliest to occur of maturity of the obligation under the Second Lien Credit Agreement or the earlier acceleration or payment in full of the same. The 2L Amendment, including the impact of the Exit Fee and Warrant Agreement finalized on August 11, 2020, resulted in the 2L Amendment meeting the criteria of debt extinguishment under the guidance of *ASC 470: Debt*. Accordingly, all debt issuance cost, including the original discount, of the original Second Lien Credit Facility, were charged to debt extinguishment loss in the accompanying Condensed Consolidated Statement of Operation in the amount of $4.1 million. Subsequently, pursuant to a waiver letter dated November 22, 2021 from AGEF to Abraxas, AGEF waived, relinquished, and abandoned all of its rights, title, and interest to the Warrant and any Common Stock underlying the Warrant for no consideration. The Company recorded a loss on the cancellation of the Warrant of approximately $2.5 million.

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The outstanding principal accrues interest at a fixed rate of 4.9%. The note is payable in monthly installments of principal and interest in the amount of $35,672. The maturity date of the note is July 20, 2023. As of December 31, 2020, and 2021, $2.8 million and $2.5 million, respectively, were outstanding on the note.

5. Property and Equipment

The major components of property and equipment, at cost, are as follows:

	Estimated Useful life Years	December 31, 2020	December 31, 2021
		(In thousands)	
Oil and gas properties (1)	-	$ 1,167,333	$ 1,165,707
Equipment and other	3-39	15,348	15,257
Drilling rig	15	24,108	24,080
		1,206,789	1,205,044
Accumulated depreciation, depletion, amortization and impairment		(1,083,843)	(1,099,075)
Net Property and Equipment		$ 122,946	$ 105,969

(1) Oil and gas properties are amortized utilizing the units of production method.

6. Stock-Based Compensation and Option Plans

The Company's Amended and Restated 2005 Employee Long-Term Equity Incentive Plan reserves 1,683,639 shares of Abraxas common stock, subject to adjustment following certain events. Awards may be in options or shares of restricted stock. Options have a term not to exceed 10 years. Options issued under this plan vest according to a vesting schedule as determined by the compensation committee of the Company's board of directors. Vesting may occur upon (1) the attainment of one or more performance goals or targets established by the committee, (2) the optionee's continued employment or service for a specified period of time, (3) the occurrence of any event or the satisfaction of any other condition specified by the committee, or (4) a combination of any of the foregoing.

Stock Options

The Company grants options to its officers, directors, and other employees under various stock option and incentive plans. There were no options granted in 2020 or 2021

The following table is a summary of the Company's stock option activity for the three years ended December 31:

	Options (000s)	Weighted average exercise price	Weighted average remaining life	Intrinsic value per share
Options outstanding December 31, 2019	297	$ 49.41		
Forfeited/Expired	(101)	48.96		
Options outstanding December 31, 2020	196	$ 49.69		
Forfeited/Expired	(141)	48.11		
Options outstanding December 31, 2021	55	53.79	3.3	$ 0.00
Exercisable at end of year	55	53.79	3.3	$ 0.00

Other information pertaining to the Company's stock option activity for the three years ended December 31:

	2020	2021
Weighted average grant date fair value of stock options granted (per share)	$ -	$ -
Total fair value of options vested (000's)	$ 275	$ -
Total intrinsic value of options exercised (000's)	$ -	$ -

As of December 31, 2021, there was no compensation cost related to non-vested awards. For the years ended December 31, 2020, we recognized $0.1 million in stock based-based compensation expense relating to options. No expense was recognized in 2021.

The following table represents the range of stock option prices and the weighted average remaining life of outstanding options as of December 31, 2021:

Range of stock option prices	Outstanding Options: Number Outstanding	Outstanding Options: Weighted average remaining life	Outstanding Options: Weighted average exercise price	Exercisable: Number Outstanding	Exercisable: Weighted average remaining life	Exercisable: Weighted average exercise price
19.40-29.99	12,700	2.9	$ 22.61	12,700	2.9	$ 22.61
30.00-39.99	5,350	5.4	$ 37.47	5,350	5.4	$ 37.47
40.00-49.99	6,228	1.4	$ 47.79	6,228	1.4	$ 47.79
50.00-59.99	8,900	4.2	$ 57.16	8,900	4.2	$ 57.16
60.00-69.99	7,594	2.2	$ 63.24	7,594	2.2	$ 63.24
70.00-79.99	6,500	2.6	$ 73.57	6,500	2.6	$ 73.57
80.00-89.99	1,500	5.5	$ 86.40	1,500	5.5	$ 86.40
90.00-99.99	3,000	5.9	$ 90.10	3,000	5.9	$ 890.10
100.00-125.60	2,450	2.3	$ 107.97	2,450	2.3	$ 107.67
	54,222	3.3	$ 53.79	54,222	3.3	$ 53.79

Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date. Compensation expense is recorded over the applicable restricted stock vesting periods. As of December 31, 2021, the total compensation cost related to non-vested awards not yet recognized was approximately $0.1 million, which will be recognized in the first quarter of 2022. For the years ended December 31, 2020 and 2021, we recognized $0.9 million and $0.6 million, respectively, in stock-based compensation expense related to restricted stock awards.

The following table is a summary of the Company's restricted stock activity for the three years ended December 31, 2021:

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2019	89	$ 31.67
Granted	-	-
Vested/Released	(33)	32.11
Forfeited/Expired	(15)	31.52
Unvested December 31, 2020	41	$ 31.37
Granted	-	-
Vested/Released	(24)	33.23
Forfeited/Expired	(3)	32.07
Unvested December 31, 2021	14	$ 27.97

Performance Based Restricted Stock Awards

Effective on April 1, 2018, the Company issued performance-based shares of restricted stock to certain officers and employees under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. The shares will vest over a three year period upon the achievement of performance goals based on the Company's Total Shareholder Return ("TSR") as compared to a peer group of companies. The number of shares which would vest depends upon the rank of the Company's TSR as compared to the peer group at the end of the three-year vesting period, and can range from zero percent of the initial grant up to 200% of the initial grant. No shares vested in 2020 or 2021 due to not achieving the performance goals.

The table below provides a summary of Performance Based Restricted Stock as of the date indicated (shares in thousands):

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2019	57	33.86
Granted	-	-
Vested/Released	-	-
Forfeited	(13)	34.29
Unvested December 31, 2020	44	$ 33.73
Granted	-	-
Vested/Released	-	-
Forfeited	(16)	45.73
Unvested December 31, 2021	28	$ 26.80

Compensation expense associated with the performance based restricted stock is based on the grant date fair value of a single share as determined using a Monte Carlo Simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the performance based restricted stock awards with shares of the Company's common stock, the awards are accounted for as equity awards and the expense is calculated on the grant date assuming a 100% target payout and amortized over the life of the awards.

As of December 31, 2021, the total compensation cost related to non-vested awards not yet recognized was approximately $0.1 million, which will be recognized in the first quarter of 2022. For each of the years ended December 31, 2020 and 2021, we recognized $0.2 million in stock-based compensation expense related to performance based restricted stock awards.

Director Stock Awards

The 2005 Directors Plan (as amended and restated) reserves 70,000 shares of Abraxas common stock, subject to adjustment following certain events. The 2005 Directors Plan provides that each year, at the first regular meeting of the board of directors immediately following Abraxas' annual stockholder's meeting, each non-employee director shall be granted or issued awards restricted stock with a value at the date of the grant of $12,000, for participation in board and committee meetings during the previous calendar year. This grant did not take place in 2020.

The maximum annual award for any one person is 1,250 shares of Abraxas common stock or options for common stock. If options, as opposed to shares, are awarded, the exercise price shall be no less than 100% of the fair market value on the date of the award while the option terms and vesting schedules are at the discretion of the committee.

At December 31, 2021, the Company had approximately 1.9 million shares reserved, under its Employee and Directors plans, for future issuance for conversion of its stock options, and incentive plans for the Company's directors, employees and consultants.

7. Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

	As of December 31, 2020	2021
	(In thousands)	
Deferred tax liabilities:		
Hedge contracts	$ 4,299	$ -
Other	2,137	2,855
Total deferred tax liabilities	6,436	2,855
Deferred tax assets:		
US full cost pool	$ 35,500	24,464
Depletion carryforward	461	470
U.S. net operating loss carryforward	84,927	96,120
Alternative minimum tax credit	-	-
Hedge contracts	-	100
Interest disallowed	2,818	5,781
Total deferred tax assets	123,706	126,935
Valuation allowance for deferred tax assets	(117,270)	(124,080)
Net deferred tax assets	6,436	2,855
Net deferred tax	$ -	$ -

Significant components of the provision (benefit) for income taxes are as follows:

	Years Ended December 31, 2020	2021
	(In thousands)	
Current:		
Federal	$ -	$ -
State	-	-
	$ -	$ -
Deferred:		
Federal	$ -	$ -
	$ -	$ -

At December 31, 2021, the Company had, $245.20 million of pre 2018 NOLs for U.S. tax purposes and $190.8 million of post 2017 NOLs for U.S. tax purposes. Our pre-2018 NOLs will expire in varying amounts from 2022 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising in 2018, 2019 and 2020 can generally be carried back five years, carried forward indefinitely and can offset 100% of future taxable income for tax years before January 1, 2021 and up to 80% of future taxable income for tax years after December 31, 2020. Any NOLs arising on or after January 1, 2021, cannot be carried back and can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes, (the alternative minimum tax no longer applies to corporations after January 1, 2018).

The use of our NOLs will be limited if there is an "ownership change" in our common stock, generally a cumulative ownership change exceeding 50% during a three year period, as determined under Section 382 of the Internal Revenue Code. As of December 31, 2021, we have not had an ownership change as defined by Section 382. Given historical losses, uncertainties exist as to the future utilization of the NOL carryforwards, therefore, the Company has established a valuation allowance of $117.27 million at December 31, 2020 and $124.08 million at December 31, 2021.

The reconciliation of income tax computed at the U.S. federal statutory tax rates to income tax expense is:

	Years Ended December 31, 2020	2021
	(in thousands)	
Tax benefit at U.S. Statutory rates	$ 38,749	$ 9,359
Change in deferred tax asset valuation allowance	(37,193)	(7,007)
Alternative minimum tax expense	-	-
Adjustment to deferred tax assets	-	(3,421)
Permanent differences	(276)	368
Return to provision estimated revision	(3,069)	-
State income taxes, net of federal effect	1,789	688
Other	-	13
	$ -	$ -

As of December 31, 2020 and 2021, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2014 through 2021 remain open to examination by the tax jurisdictions to which the Company is subject.

New tax legislation, commonly referred to as the Tax Cuts and Jobs Act (H.R. 1), was enacted on December 22, 2017. Since our federal deferred tax asset was fully offset by a valuation allowance, the reduction in the U.S. corporate income tax rate to 21% did not materially affect the Company's financial statements. Significant provisions that may impact income taxes in future years include: the repeal of the corporate Alternative Minimum Tax, the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income for levered balance sheets, (for tax years 2019 & 2020, the CARES Act temporarily adjusted the limitation in excess of 50% of adjusted taxable income for levered balance sheets at the taxpayer's discretionary election), a limitation on utilization of net operating losses generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of net operating losses generated after tax year 2017, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to the availability of our net operating loss carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation may have a significant effect on this projection.

8. Commitments and Contingencies

Litigation and Contingencies

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2021, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

9. Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Years Ended December 31, 2020	2021
Numerator:		
Net loss	$ (184,522)	$ (44,567)
Denominator for basic earnings per share - weighted-average common shares outstanding	8,382	8,408
Effect of dilutive securities: Stock options, restricted shares and performance based shares	-	-

Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares	8,382	8,408
Net loss per common share - basic	$ (22.01)	$ (5.30)
Net loss per common share - diluted	$ (22.01)	$ (5.30)

Basic earnings per share, excluding any dilutive effects of stock options and unvested restricted stock, is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted income (loss) per share is computed similar to basic; however diluted income (loss) per share reflects the assumed conversion of all potentially dilutive securities.

10. Benefit Plans

The Company has a defined contribution plan (401(k) plan) covering all eligible employees. For 2020, in accordance with the safe harbor provisions of the Plan, the Company contributed $142,820. The Company contributed $123,639 to the plan for 2021, and will contribute an additional $1,637 in 2022 for 2021. The Company adopted the safe harbor provisions which requires it to contribute a fixed match to each participating employee's contribution to the plan. The fixed match is set at the rate of dollar for dollar on the first 1% of eligible pay contributed, then 50 cents on the dollar for each additional percentage point of eligible pay contributed, up to 5%. Each employee's eligible pay with respect to calculating the fixed match is limited by IRS regulations. In addition, the Board of Directors, at its sole discretion, may authorize the Company to make additional contributions to each participating employee. The employee contribution limit for 2020 and 2021 was $19,500 for employees under the age of 50 and $26,000 for employees 50 years of age or older.

11. Hedging Program and Derivatives

As of December 31, 2021 the Company is not party to any hedge agreements. The liability as of December 31, 2021 relates to the December 2021 contract settlement.

The following table illustrates the impact of derivative contracts on the Company's balance sheet:

Fair Value Derivative Contracts as of December 31, 2020

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$ 9,639	Derivatives - current	$ 480
Commodity price derivatives	Derivatives - long-term	10,281	Derivatives - long-term	-
		$ 19,920		$ 480

Fair Value Derivative Contracts as of December 31, 2021

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$ -	Derivatives - current	$ 442
		$ -		$ 442

Gains and losses from derivative activities are reflected as "Loss (gain) on derivative contracts" in the accompanying Consolidated Statements of Operations. The net estimated value of our commodity derivative contracts was a liability of approximately $0.4 million as of December 31, 2021. For the year-ended December 31, 2021, we recognized a loss of $33.0 million related to our derivative contracts, including a loss or $7.1 million related to cancelled contracts. For the year ended December 31, 2020, we recognized a gain on our derivative contracts of approximately $42.9 million.

12. Financial Instruments

There is a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2020 and 2021, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2020
Assets:				
NYMEX fixed price derivative contracts	$ -	$ 19,920	$ -	$ 19,920
Total Assets	$ -	$ 19,920	$ -	$ 19,920
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 480	$ -	$ 480
Total Liabilities	$ -	$ 480	$ -	$ 480

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2021
Assets:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$ -
Total Assets	$ -	$ -	$ -	$ -
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 442	$ -	$ 442
Total Liabilities	$ -	$ 442	$ -	$ 442

The Company's derivative contracts during the years ended December 31, 2021 and December 31, 2020 consisted of NYMEX-based fixed price commodity swaps and basis differential swaps. The NYMEX-based fixed price derivative contracts were indexed to

NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2.

Nonrecurring Fair Value Measurements

Non-financial assets and liabilities measured at fair value on a nonrecurring basis included certain non-financial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used. The assessment considers the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, the economic viability of development if proved reserves were assigned and other current market conditions. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligation is presented in Note 1.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

13. Lease Accounting Standard

Nature of Leases

We lease certain real estate, field equipment and other equipment under cancelable and non-cancelable leases to support our operations. A more detailed description of our significant lease types is included below.

Real Estate Leases

We rented a residence in North Dakota from a third party for living accommodations for certain field employees. Our real estate lease was non-cancelable with a term of five years, through August 31, 2024. We have concluded our real estate agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. Upon completion of the primary term, both parties have substantive rights to terminate the lease. As a result, enforceable rights and obligations do not exist under the rental agreements subsequent to the primary term. The North Dakota residential lease was assigned to a third-party on January 3, 2022. See Note 14 "Subsequent Events."

Field Equipment

We rent compressors and coolers from third parties in order to facilitate the downstream movement of our production from our drilling operations to market. Our compressor and cooler arrangements are typically structured with a non-cancelable primary term of one year and continue thereafter on a month-to-month basis subject to termination by either party with thirty days' notice. These leases are considered short term and are not capitalized. We have a small number of compressor leases that are longer than twelve months. We have concluded that our compressor and cooler rental agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. Upon completion of the primary term, both parties have substantive rights to terminate the lease. As a result, enforceable rights and obligations do not exist under the rental agreement subsequent to the primary term. We enter into daywork contracts for drilling rigs with third parties to support our drilling activities. Our drilling rig arrangements are typically structured with a term that is in effect until drilling operations are completed on a contractually specified well or well pad. Upon mutual agreement with the contractor, we typically have the option to extend the contract term for additional wells or well pads by providing thirty days' notice prior to the end of the original contract term. We have concluded that our drilling rig arrangements represent short-term operating leases. The accounting guidance requires us to make an assessment at contract commencement if we are reasonably certain that we will exercise the option to extend the term. Due to the continuously evolving nature of our drilling schedules and the potential volatility in commodity prices in an annual period, our strategy to enter into shorter term drilling rig arrangements allows us the flexibility to respond to changes in our operating and economic environment. We exercise our discretion in choosing to extend or not extend contracts on a rig by rig basis depending on the conditions present at the time the contract expires. At the time of contract commencement, we have determined we cannot conclude with reasonable certainty if we will choose to extend the contract beyond its original term. Pursuant to the full cost method, these costs are capitalized as part of natural gas and oil properties on our balance sheet when paid.

Discount Rate

Our leases typically do not provide an implicit rate. Accordingly, we are required to use our incremental borrowing rate in determining the present value of lease payments based on the information available at commencement date. Our incremental borrowing rate reflects the estimated rate of interest that we would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. We use the implicit rate in the limited circumstances in which that rate is readily determinable.

Practical Expedients and Accounting Policy Elections

Certain of our lease agreements include lease and non-lease components. For all existing asset classes with multiple component types, we have utilized the practical expedient that exempts us from separating lease components from non-lease components. Accordingly, we account for the lease and non-lease components in an arrangement as a single lease component. In addition, for all of our existing asset classes, we have made an accounting policy election not to apply the lease recognition requirements to our short-term leases (that is, a lease that, at commencement, has a lease term of 12 months or less and does not include an option to purchase the underlying asset that we are reasonably certain to exercise). Accordingly, we recognize lease payments related to our short-term leases in our statement of operations on a straight-line basis over the lease term which has not changed from our prior recognition. To the extent that there are variable lease payments, we recognize those payments in our statement of operations in the period in which the obligation for those payments is incurred. None of our current leases contain variable payments. Refer to "Nature of Leases" above for further information regarding those asset classes that include material short-term leases.

The components of our total lease expense for the years ended December 31, 2020 and December 31, 2021, the majority of which is included in lease operating expense, are as follows:

	For the Year Ended December 31,	
	2020	2021
	(in thousands)	
Operating lease cost	$ 114	$ 65
Short-term lease expense (1)	2,183	1,913
Total lease expense	$ 2,297	$ 1,978
Short-term lease costs (2)	$ 973	$ -

(1) Short-term lease expense represents expense related to leases with a contract term of 12 months or less.
(2) These short-term lease costs are related to leases with a contract term of 12 months or less which are related to drilling rigs and are capitalized as part of natural gas and oil properties on our balance sheet.

Supplemental balance sheet information related to our operating leases is included in the table below:

	For the Year Ended December 31,	
	2020	2021
	(in thousands)	
Operating lease Right of Use asset	$ 228	$ 173
Operating lease liability - current	$ 53	$ 40
Operating lease liabilities - long-term	$ 150	$ 110

Our weighted average remaining lease term and weighted average discount rate for our operating leases are as follows:

	For the Year Ended December 31,	
	2020	2021
	(in thousands)	
Weighted Average Remaining Lease Term (in years)	10.68	12.46
Weighted Average Discount Rate	6%	6%

Our lease liabilities with enforceable contract terms that are greater than one year mature as follows:

	Operating Leases (in thousands)
2022	40
2023	41
2024	28
2025	4
2026	4
Thereafter	94
Total lease payments	211
Less imputed interest	(61)
Total lease liability	$ 150

Supplemental cash flow information related to our operating leases is included in the table below:

	For the Year Ended December 31,	
	2020	2021
	(in thousands)	
Cash paid for amounts included in the measurement of lease liabilities	$ 114	$ 65
Right of Use assets added in exchange for lease obligations (since adoption)	$ 125	$ -

14. Subsequent Events

Restructuring

Pursuant to the Exchange Agreement, dated as of January 3, 2022, between Abraxas and AG Energy Funding, LLC ("AGEF") and certain other agreements entered into by Abraxas on January 3, 2022, we effectuated a restructuring of our then-existing indebtedness through a multi-part interdependent de levering transaction consisting of: (i) an Asset Purchase and Sale Agreement pursuant to which Abraxas sold to Lime Rock Resources V-A, L.P. certain oil, gas, and mineral properties in the Williston Basin region of North Dakota and other related assets belonging to the Company and its subsidiaries for $87,200,000 in cash ($73.3 million after customary closing adjustments) (the "Sale"), (ii) the pay down of the indebtedness and other obligations of Abraxas and its subsidiaries under the First Lien Credit Facility, by and among Abraxas, the financial institutions party thereto as lenders, and Société Générale, as "Issuing Lender" and administrative agent and certain specified secured hedges from the proceeds of the Sale and, to the extent necessary, other cash of Abraxas; and (iii), a debt for equity exchange of the indebtedness and other obligations of Abraxas and its subsidiaries under the Second Lien Credit Facility, by and among Abraxas, the financial institutions party thereto as lenders, and Angelo Gordon Energy Servicer, LLC, as administrative agent and all related loan and security documents (the "Exchange" and, together with the transactions referred to in clauses (i) and (ii), the "Restructuring").

AGEF was issued 685,505 shares of Series A Preferred Stock of the Company in the Exchange. The Series A Preferred Stock has the terms set forth in the Company's filed Preferred Stock Certificate of Designation (the "Certificate). Pursuant to the Certificate, any proceeds distributed to the Company's stockholders or otherwise received in respect of the capital stock of the Company in a merger or other liquidity event will be allocated among the Series A Preferred Stock and the Company's common stock as follows: (1) first, 100% to the Series A Preferred Stock until the Series A Preferred Stock has received $100 million of proceeds in the aggregate (the "Tier One Preference Amount"), (2) second, 95% to the Series A Preferred Stock and 5% to the Company's common stock until the Series A Preferred Stock has received $137.1 million, plus a 6.0% annual rate of return thereon from the date hereof; (3) thereafter, 75% to the Series A Preferred Stock and 25% to the Company's common stock. The Exchange Agreement entered into in connection with the Restructuring also provides for the potential funding by AGEF of an additional amount up to $12.0 million, if agreed to by AGEF and the disinterested members of the Company's Board of Directors. Any such additional amount funded would result in an increase to the Tier One Preference Amount equal to 1.5 x the amount of such additional funding. The shares of Series A Preferred Stock vote together as a single class with the Company's common stock, and each share of Series A Preferred Stock entitles the holder thereof to 69 votes. Accordingly, AGEF's ownership of the Series A Preferred Stock entitle it to approximately 85% of the voting power of the Company's current outstanding capital stock.

Todd Dittmann, Damon Putman and Daniel Baddeloo, each of whom are employees of AGEF, were appointed to Abraxas' Board of Directors.

Change In Majority of Board of Directors

Todd Dittmann, Damon Putman and Daniel Baddeloo, each of whom are employees of AGEF were appointed as members of the Board of Directors in January 2022.

15. Events of Default

In connection with the completion of our financial statements for the year ended December 31, 2020, the Company tested its financial ratios for the fiscal quarter ended December 31, 2020 and determined that it was not in compliance the first lien debt to consolidated EBITDAX ratio covenant under the First Lien Credit Facility. Our failure to comply with such covenant contributed to our independent accountant's including an explanatory paragraph with regard to the Company's ability to continue as a "going concern" in issuing their opinion on our financial statements for the year ended December 31, 2020. The "going concern" opinion resulted in an additional event of default under the First Lien Credit Facility and the Second Lien Credit Facility. Additional events of default occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended. However, in connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

First Lien Credit Facility

Events of default have occurred under the First Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its inability to comply with the first lien debt to consolidated EBITDAX ratio for the fiscal quarter ended December 31, 2020, (iii) our failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the First Lien Credit Facility, and (iv) certain cross-defaults that occurred, or may occur, as a result of the events of default under the First Lien Credit Agreement and corresponding cross-defaults under the Second Lien Credit Facility and cross-defaults or similar termination events under our hedging contracts. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

Second Lien Credit Facility

Events of default occurred under the Second Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the Second Lien Credit Facility, (iii) the failure of the Company to meet certain hedging requirements, (iv) the Company's inability to comply with the total leverage ratio for the fiscal quarter ended September 30, 2021, (v) the Company's inability to comply with minimum asset coverage ratio for the fiscal quarter ended September 30, 2021, and (vi) certain cross-defaults that occurred, or may could have occurred, as a result of the occurrence of events of default under the First Lien Credit Facility and corresponding cross-defaults or similar termination events under our hedging contracts. Additional events of default occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended.

On April 16, 2021, we received a Notice of Default and Reservation of Rights (the "Notice of Default") from Angelo Gordon stating that we have defaulted under the Second Lien Credit Facility, and that, as a result, the lenders have accelerated our obligations due thereunder and have reserved their rights to pursue additional remedies in the future.

The Notice of Default declared that our obligations under the Second Lien Credit Facility were immediately due and payable, in each case without presentment, demand, protest or other requirements of any kind, and we began to bear interest at the rate applicable to such amount under the Second Lien Credit Facility, plus an additional 3%. Additionally, the administrative agent and the lenders reserved their right to exercise further rights, powers and remedies under the Second Lien Credit Facility, at any time or from time to time, with respect to any of the events of default described above. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

Hedging Contracts

Effective April 12, 2021, Morgan Stanley Capital Group, Inc. ("Morgan Stanley"), a hedge counterparty to several of our hedging contracts sent us notice of events of default and early termination with respect to the hedging contracts to which they are a counterparty. The notice indicated Morgan Stanley's election to exercise termination rights under the hedge contract, which Morgan Stanley asserted arose as a result of the occurrence of events of default under the First Lien Credit Facility, of which Morgan

Stanley is a lender, holding approximately 3.7% of the outstanding obligations under the First Lien Credit Facility. The termination value of the hedging agreements with Morgan Stanley as of the effective date of the notice was approximately $9.2 million. We subsequently voluntarily terminated most of our other hedging arrangements. As a result of the settlement of the terminated hedges, we had outstanding obligations of $9.2 million, including the $8.4 million to Morgan Stanley. These obligations were added to the outstanding balance of the First Lien Credit Facility and accrued interest at the default rate until repaid. Our other hedging agreements were also terminated. As of December 31, 2021, we no longer had any hedging agreements in place.

16. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying tables present information concerning the Company's oil and gas producing activities "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows as of December 31, 2020 and 2021:

	Years Ended December 31, (in thousands)	
	2020	**2021**
Proved oil and gas properties	$ 1,167,333	$ 1,165,707
Unproved properties	-	-
Total	1,167,333	1,165,707
Accumulated depreciation, depletion, amortization and impairment	(1,060,649)	(1,074,144)
Net capitalized costs	$ 106,684	$ 91,563

Cost incurred in oil and gas property acquisition and development activities were as follows for the years ended December 31, 2020 and 2021 (in thousands):

	2020	**2021**
Development costs	$ 5,238	$ 1,145
Exploration costs	-	-
Property acquisition costs	-	-
	$ 5,238	$ 1,145

Results of operations from oil and gas producing activities were as follows for the years ended December 31, 2020 and 2021:

	2020	2021
Revenues	$ 42,984	$ 78,836
Production costs	(21,090)	(24,137)
Depreciation, depletion and amortization	(22,679)	(13,495)
Accretion of future site restoration	(414)	(330)
Proved property impairment	(186,980)	-
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ (188,179)	$ 40,874
Depletion rate per barrel of oil equivalent	$ 12.58	$ 6.67

Estimated Quantities of Proved Oil and Gas Reserves

Reserve estimates are inherently imprecise and estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. The estimates have been predominately prepared by independent petroleum reserve engineers. Proved oil and gas reserves are the estimated quantities of oil and 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. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company’s proved reserves are located in the continental United States.

Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements; therefore, the unweighted average prior 12-month first-day-of-the-month commodity prices and year-end costs were used in estimating reserve volumes and future net cash flows for the periods presented.

The following table presents the Company's estimate of its net proved developed and undeveloped oil and gas reserves as of December 31, 2020 and 2021:

	Total			
	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Oil Equivalents (Mboe)
Proved Developed Reserves:				
December 31, 2020	9,538	3,187	24,318	16,778
December 31, 2021	6,883	2,914	30,158	14,823
Proved Undeveloped Reserves:				
December 31, 2020	-	-	-	-
December 31, 2021	-	-	-	-

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company's proved oil and gas reserves have been estimated by the independent petroleum engineering firm, DeGolyer & MacNaughton, assisted by the engineering and operations departments of the Company as of December 31, 2020 and December 31, 2021. The following information has been prepared in accordance with SEC rules and accounting standards based on the 12-month first-day-of-the-month unweighted average prices in accordance with provisions of the FASB's Accounting Standards Update No. 2010-03, "Extractive Activities—Oil and Gas (Topic 932)." Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis and net operating losses associated with the properties. Since prices used in the calculation are average prices for 2020, and 2021, the standardized measure could vary significantly from year to year based on the market conditions that occurred during a given year.

The technical personnel responsible for preparing the reserve estimates at DeGolyer & MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer & MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. All reports by DeGolyer & MacNaughton were developed utilizing studies performed by DeGolyer & MacNaughton and assisted by the Engineering and Operations departments of Abraxas. Reserves are estimated by independent petroleum engineers. The report of DeGolyer & MacNaughton dated February 4, 2022, contains further discussions of the reserve estimates and evaluations prepared by DeGolyer & MacNaughton as well as the qualifications of DeGolyer & MacNaughton's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of proved reserves at December 31, 2020 and 2021 were based on studies performed by our independent petroleum engineers assisted by the Engineering and Operations departments of Abraxas. The Engineering department is directly responsible for Abraxas' reserve evaluation process. The Vice President of Engineering is the manager of this department and is the primary technical person responsible for this process. The Vice President of Engineering holds a Bachelor of Science degree in Petroleum Engineering and has 42 years of experience in reserve evaluations. The Vice President of Engineering is a Registered Professional Engineer in the State of Texas. The operations department of Abraxas assisted in the process.

The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted to represent the fair market value of the Company's proved oil and gas reserves. An estimate of fair market value would also take into account, among other factors, the recovery of reserves not classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure. The table below sets forth the Standardized Measure of our proved oil and gas reserves for the years ended December 31, 2020 and 2021 :

	Years Ended December 31, (in thousands)	
	2020	2021
Future cash inflows	$ 345,869	$ 485,982
Future production costs	(166,781)	(222,309)
Future development costs	(6,291)	(5,623)
Future income tax expense	-	-
Future net cash flows	172,797	258,050
Discount	$ (66,113)	$ (104,775)
Standardized Measure of discounted future net cash relating to proved reserves	$ 106,684	$ 153,275

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Exhibit Index

4.1 Description of Securities. (Filed herewith),

23.1 Consent of ADKF P.C. (Filed herewith).

23.3 Consent of DeGolyer and MacNaughton. (Filed herewith).

31.1 Certification – Chief Executive Officer. (Filed herewith).

31.2 Certification – Chief Financial Officer. (Filed herewith).

32.1 Certification by Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).

32.2 Certification by Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (Filed herewith).

99.1 DeGolyer and MacNaughton's report with respect to oil and reserves of Abraxas Petroleum. (Filed herewith).

101.INS	Inline XBRL Instance Document (the Instance Document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document)
101.SCH	Inline XBRL Taxonomy Extension Schema Document
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document

101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Management Compensatory Plan or Agreement.

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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.

ABRAXAS PETROLEUM CORPORATION

By:	/s/Robert L.G. Watson President and Principal Executive Officer	By:	/s/Steven P. Harris Vice President and Chief Financial Officer Principal Financial Officer	By:	/s/ G. William Krog, Jr. Vice President and Chief Accounting Officer Principal Accounting Officer

DATED: March 31, 2022

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 date indicated.

Signature	Name and Title	Date
/s/ Robert L.G. Watson Robert L.G. Watson	President (Principal Executive Officer) and Director	March 31, 2022
/s/ Steven P. Harris Steven P. Harris	Vice President, CFO (Principal Financial Officer)	March 31, 2022
/s/ G. William Krog, Jr. G. William Krog, Jr.	Vice President, Chief Accounting Officer (Principal Accounting Officer)	March 31, 2022
/s/ Todd Dittmann Todd Dittmann	Chairman of the Board, Director	March 31, 2022
/s/ Brian L. Melton Brian L. Melton	Director	March 31, 2022
/s/ Damon Putman Damon Putman	Director	March 31, 2022
/s/ Daniel Baddeloo **Daniel Baddeloo**	Director	March 31, 2022

Exhibit 4.1

DESCRIPTION OF SECURITIES
REGISTERED UNDER SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following is a summary of Abraxas Petroleum Company's (the "Company") classes of securities registered under Section 12 of the Securities Exchange Act of 1934 and outstanding as of the end of the period covered by this report.

Common Stock

As of March 18, 2022, we had 20,000,000 shares of common stock, par value $0.01 per share, authorized of which 8,421,910 were outstanding with approximately 112 stockholders of record.

Holders of our common stock are entitled to cast one vote for each share held of record on all matters submitted to a vote of stockholders and are not entitled to cumulate votes for the election of directors. Holders of our common stock do not have preemptive rights to subscribe for additional shares of common stock issued by us.

Holders of our common stock are entitled to receive dividends as may be declared by the board of directors out of funds legally available for that purpose. Under the terms of our credit facility, we are prohibited from paying dividends on shares of our common stock.

In the event of liquidation, holders of our common stock are entitled to share pro rata in any distribution of our assets remaining after payment of liabilities, subject to the preferences and rights of the holders of any outstanding shares of preferred stock. All of the outstanding shares of our common stock are fully paid and non-assessable.

Preferred Stock

Our articles of incorporation authorize the issuance of up to 1,000,000 shares of preferred stock, par value $0.01 per share, in one or more series. The description of preferred stock set forth below and the description of the terms of a particular series of preferred stock set forth in any applicable prospectus supplement are not complete and are qualified in their entirety by reference to our articles of incorporation and to the certificate of designation relating to that series of preferred stock. The certificate of designation for any series of preferred stock will be filed with the Securities and Exchange Commission promptly after any offering of that series of preferred stock.

The particular terms of any series of preferred stock being offered by us under this shelf registration will be described in the prospectus supplement relating to that series of preferred stock. If so indicated in the prospectus supplement relating to a particular series of preferred stock, the terms of any such series of preferred stock may differ from the terms set forth below. The terms of the preferred stock may include:

- the title of the series and the number of shares in the series;

- the price at which the preferred stock will be offered;

- the dividend rate or rates or method of calculating the rates, the dates on which the dividends will be payable, whether or not dividends will be cumulative or noncumulative and, if cumulative, the dates from which dividends on the preferred stock being offered will cumulate;

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•the voting rights, if any, of the holders of shares of the preferred stock being offered;

•the provisions for a sinking fund, if any, and the provisions for redemption, if applicable, of the preferred stock being offered;

•the liquidation preference per share;

•the terms and conditions, if applicable, upon which the preferred stock being offered will be convertible into our common stock, including the conversion price, or the manner of calculating the conversion price, and the conversion period;

•the terms and conditions, if applicable, upon which the preferred stock will be exchangeable for debt securities, including the exchange price, or the manner of calculating the exchange price, and the exchange period;

•any listing of the preferred stock being offered on any securities exchange;

•whether interests in the share of the series will be represented by depositary shares;

•the relative ranking and preferences of the preferred stock being offered as to dividend rights and rights upon liquidation, dissolution or the winding up of our affairs;

•any limitation on the issuance of any class or series of preferred stock ranking senior or equal to the series of preferred stock being offered as to dividend rights and rights upon liquidation, dissolution or the winding up of our affairs; and

•any additional rights, preferences, qualifications, limitations and restrictions of the series.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

Abraxas Petroleum Corporation
San Antonio, Texas

We consent to the incorporation by reference in the registration statements on Form S-8 (No. 333-206521, No. 333-221184, and No. 333-231645) of our report dated March 31, 2022, with respect to the consolidated financial statements of Abraxas Petroleum Corporation included in the Annual Report (Form 10-K) for the year ended December 31, 2021.

We further consent to our designation as an expert in accounting and auditing.

/s/ ADKF, P.C.

San Antonio, Texas
March 31, 2022

Exhibit 23.3

DeGolyer and MacNaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

March 31, 2022

Abraxas Petroleum Corporation
18803 Meisner Drive
San Antonio, TX 78258

Ladies and Gentlemen:

We consent to the use of the name DeGolyer and MacNaughton, to references to DeGolyer and MacNaughton, and to the inclusion of information taken from our reports entitled "Report as of December 31, 2021 on Reserves and Revenue of Certain Properties with interests attributable to Abraxas Petroleum Corporation" and "Report as of December 31, 2020 on Reserves and Revenue of Certain Properties with interests attributable to Abraxas Petroleum Corporation" (our Reports) under the headings "Item 1. Business – General," "Item 2. Properties – Reserves Information," and "Notes to Consolidated Financial Statements – 16. Supplemental Oil and Gas Disclosures (Unaudited)" in the Abraxas Petroleum Corporation Annual Report on Form 10-K for the year ended December 31, 2021. We also consent to the inclusion of our report of third party dated February 4, 2022, in the Annual Report on Form 10-K of Abraxas Petroleum Corporation as Exhibit 99.1. We further consent to the incorporation by reference in the Registration Statements on Form S-3 (File Nos. 333-212342 and 333-219873), Form S-4 (File No. 333-212340), and Form S-8 (File Nos. 333-219877, 333-17375, 333-17377, 033-81416, 333-55691, 333-74614, 333-74592, 333-135032, 333-153635, 333-162358, 333-168022, 333-188117, 333-204744, and 333-212341) of information from our Reports.

Very truly yours,

/s/ DeGolyer and MacNaughton

DeGOLYER and MacNAUGHTON
Texas Registered Engineering Firm F-716

Exhibit 31.1

CERTIFICATIONS

I, Robert L. G. Watson, certify that:

1. I have reviewed this annual report on Form 10-K of Abraxas Petroleum Corporation.

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls 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 fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

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

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

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

Date: March 31, 2022
/s/ Robert L.G. Watson
Robert L.G. Watson
Chairman of the Board, President and Principal Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Steven P. Harris, certify that:

1. I have reviewed this annual report on Form 10-K of Abraxas Petroleum Corporation.

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

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

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls 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 fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

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

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

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

Date: March 31, 2022
/s/Steven P. Harris
Steven P. Harris
Vice President and Principal Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Abraxas Petroleum Corporation (the “Company”) on Form 10-K for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert L.G. Watson, Chairman of the Board, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 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.

/s/ Robert L.G. Watson
Robert L.G. Watson
Chairman of the Board, President and Chief Executive Officer
March 31, 2022

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of §18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

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 of Abraxas Petroleum Corporation (the “Company”) on Form 10-K for the year ended December 31, 2021 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Steven P. Harris, Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 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.

/s/Steven P. Harris
Steven P. Harris
Vice President and Chief Financial Officer
March 31, 2022

This certification accompanies the Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the Company for purposes of §18 of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 99.1

DeGolyer and MacMaughton
5001 Spring Valley Road
Suite 800 East
Dallas, Texas 75244

February 4, 2022

Abraxas Petroleum Corporation
18803 Meisner Drive
San Antonio, Texas 78258

Ladies and Gentlemen:

Pursuant to your request, this report of third party presents an independent evaluation, as of December 31, 2021, of the extent and value of the estimated net proved oil, natural gas liquids (NGL), and gas reserves of certain properties in which Abraxas Petroleum Corporation (Abraxas) has represented it holds an interest. This evaluation was completed on February 4, 2022. The properties evaluated herein consist of working interests located in Texas. Abraxas has represented that these properties account for 98 percent on a net equivalent barrel basis of Abraxas' net proved reserves as of December 31, 2021. The net proved reserves estimates have been prepared in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the United States Securities and Exchange Commission (SEC). This report was prepared in accordance with guidelines specified in Item 1202 (a)(8) of Regulation S–K and is to be used for inclusion in certain SEC filings by Abraxas.

Reserves estimates included herein are expressed as net reserves. Gross reserves are defined as the total estimated petroleum remaining to be produced from these properties after December 31, 2021. Net reserves are defined as that portion of the gross reserves attributable to the interests held by Abraxas after deducting all interests held by others.

Values for proved reserves in this report are expressed in terms of future gross revenue, future net revenue, and present worth. Future gross revenue is defined as that revenue which will accrue to the evaluated interests from the production and sale of the estimated net reserves. Future net revenue is calculated by deducting production taxes, ad valorem taxes, operating expenses, capital costs, and abandonment costs from future gross revenue. Operating expenses include field operating expenses, transportation and processing expenses, compression charges, and an allocation of overhead that directly relates to production activities. Capital costs include drilling and completion costs, facilities costs, and field maintenance costs. Abandonment costs are represented by Abraxas to be inclusive of those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment. At the request of Abraxas, future income taxes were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a nominal discount rate of 10 percent per year compounded annually over the expected period of realization. Present worth should not be construed as fair market value because no consideration was given to additional factors that influence the prices at which properties are bought and sold.

Estimates of reserves and revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

Information used in the preparation of this report was obtained from Abraxas and from public sources. In the preparation of this report we have relied, without independent verification, upon information furnished by Abraxas with respect to the property interests being evaluated, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information and data that were accepted as represented. A field examination was not considered necessary for the purposes of this report.

<u>Definition of Reserves</u>

Petroleum reserves included in this report are classified as proved. Only proved reserves have been evaluated for this report. Reserves classifications used in this report are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC. Reserves are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analyses of production-decline curves, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs consistent with the effective date of this report, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved oil and gas reserves – Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
(A) The area identified by drilling and limited by fluid contacts, if any, and (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by 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, excluding escalations based upon future conditions.

Developed oil and gas reserves – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped oil and gas reserves – Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in [section 210.4–10 (a) Definitions], or by other evidence using reliable technology establishing reasonable certainty.

Methodology and Procedures

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with the reserves definitions of Rules 4–10(a) (1)–(32) of Regulation S–X of the SEC and with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (revised June 2019) Approved by the SPE Board on 25 June 2019" and in Monograph 3 and Monograph 4 published by the Society of Petroleum Evaluation Engineers. The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by Abraxas, and analyses of areas offsetting existing wells with test or production data, reserves were classified as proved. The proved undeveloped reserves estimates were based on opportunities identified in the plan of development provided by Abraxas.

Abraxas has represented that its senior management is committed to the development plan provided by Abraxas and that Abraxas has the financial capability to execute the development plan, including the drilling and completion of wells and the installation of equipment and facilities.

For the evaluation of unconventional reservoirs, a performance-based methodology integrating the appropriate geology and petroleum engineering data was utilized for this report. Performance-based methodology primarily includes (1) production diagnostics, (2) decline-curve analysis, and (3) model-based analysis (if necessary, based on availability of data). Production diagnostics include data quality control, identification of flow regimes, and characteristic well performance behavior. These analyses were performed for all well groupings (or type-curve areas).

Characteristic rate-decline profiles from diagnostic interpretation were translated to modified hyperbolic rate profiles, including one or multiple b-exponent values followed by an exponential decline. Based on the availability of data, model-based analysis may be integrated to evaluate long-term decline behavior, the effect of dynamic reservoir and fracture parameters on well performance, and complex situations sourced by the nature of unconventional reservoirs.

In the evaluation of undeveloped reserves, type-well analysis was performed using well data from analogous reservoirs for which more complete historical performance data were available.

Data provided by Abraxas from wells drilled through December 31, 2021, and made available for this evaluation were used to prepare the reserves estimates herein. These reserves estimates were based on consideration of monthly production data available for certain properties only through September 2021. Estimated cumulative production, as of December 31, 2021, was deducted from the estimated gross ultimate recovery to estimate gross reserves. This required that production be estimated for up to 3 months.

Oil reserves estimated herein are those to be recovered by normal field separation. NGL reserves estimated herein include pentanes and heavier fractions (C_{5+}) and liquefied petroleum gas (LPG), which consists primarily of propane and butane fractions, and are the result of low-temperature plant processing. Oil and NGL reserves included in this report are expressed in thousands of barrels (Mbbl). In these estimates, 1 barrel equals 42 United States gallons.

Gas quantities estimated herein are expressed as sales gas. Sales gas is defined as the total gas to be produced from the reservoirs, measured at the point of delivery, after reduction for fuel usage, flare, and shrinkage resulting from field separation and processing. Gas reserves estimated herein are reported as sales gas. Gas quantities are expressed at a temperature base of 60 degrees Fahrenheit (°F) and at a pressure base of 14.65 pounds per square inch absolute (psia). Gas quantities included in this report are expressed in millions of cubic feet (MMcf).

Gas quantities are identified by the type of reservoir from which the gas will be produced. Nonassociated gas is gas at initial reservoir conditions with no oil present in the reservoir. Associated gas is both gas-cap gas and solution gas. Gas-cap gas is gas at initial reservoir conditions and is in communication with an underlying oil zone. Solution gas is gas dissolved in oil at initial reservoir conditions. Gas quantities estimated herein include only associated gas.

At the request of Abraxas, sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

Primary Economic Assumptions

Revenue values in this report were estimated using initial prices, expenses, and costs provided by Abraxas. Future prices were estimated using guidelines established by the SEC and the Financial Accounting Standards Board (FASB). The following economic assumptions were used for estimating the revenue values reported herein:

Oil and NGL Prices

Abraxas has represented that the oil and NGL prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The oil and NGL prices were calculated using differentials furnished by Abraxas to a West Texas Intermediate (WTI) price of $66.55 per barrel and held constant thereafter. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $62.89 per barrel of oil and $13.58 per barrel of NGL.

Gas Prices

Abraxas has represented that the gas prices were based on a reference price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual agreements. The gas prices were calculated for each property using differentials furnished by Abraxas to a Henry Hub (HH) price of $3.64 per million Btu and held constant thereafter. Btu factors provided by Abraxas were used to convert prices from dollars per million Btu to dollars per thousand cubic feet. The volume-weighted average price attributable to the estimated proved reserves over the lives of the properties was $1.848 per thousand cubic feet of gas.

Production and Ad Valorem Taxes

Production taxes were calculated using the tax rates for Texas, including, where appropriate, abatements for enhanced recovery programs. Ad valorem taxes were calculated using rates provided by Abraxas based on recent payments.

Operating Expenses, Capital Costs, and Abandonment Costs

Estimates of operating expenses, provided by Abraxas and based on current expenses, were held constant for the lives of the properties. Future capital expenditures were estimated using 2021 values, provided by Abraxas, and were not adjusted for inflation. In certain cases, future expenditures, either higher or lower than current expenditures, may have been used because of anticipated changes in operating conditions, but no general escalation that might result from inflation was applied. Abandonment costs, which are those costs associated with the removal of equipment, plugging of wells, and reclamation and restoration associated with the abandonment, were provided by Abraxas for all properties and were not adjusted for inflation. Operating expenses, capital costs, and abandonment costs were considered, as appropriate, in determining the economic viability of the undeveloped reserves estimated herein.

In our opinion, the information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, NGL, and gas contained in this report has been prepared in accordance with Paragraphs 932-235-50-4, 932-235-50-6, 932-235-50-7, 932-235-50-9, 932-235-50-30, and 932-235-50-31(a), (b), and (e) of the Accounting Standards Update 932-235-50, *Extractive Industries – Oil and Gas (Topic 932): Oil and Gas Reserve Estimation and Disclosures* (January 2010) of the FASB and Rules 4–10(a) (1)–(32) of Regulation S–X and Rules 302(b), 1201, 1202(a) (1), (2), (3), (4), (8), and 1203(a) of Regulation S–K of the SEC; provided, however, that (i) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (ii) estimates of the proved developed and proved undeveloped reserves are not presented at the beginning of the year.

To the extent the above-enumerated rules, regulations, and statements require determinations of an accounting or legal nature, we, as engineers, are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Summary of Conclusions

The estimated net proved reserves, as of December 31, 2021, of the properties evaluated herein were based on the definition of proved reserves of the SEC and are summarized as follows, expressed in thousands of barrels (Mbbl), millions of cubic feet (MMcf), and thousands of barrels of oil equivalent (Mboe):

	Estimated by DeGolyer and MacNaughton Net Proved Reserves as of December 31, 2021			
	Oil (Mbbl)	NGL (Mbbl)	Sales Gas (MMcf)	Oil Equivalent (Mboe)
Proved Developed	3,692	612	4,612	5,073
Proved Undeveloped	12,940	1,063	8,096	15,352
Total Proved	**16,632**	**1,675**	**12,708**	**20,425**

Note: Sales gas reserves estimated herein were converted to oil equivalent using an energy equivalent factor of 6,000 cubic feet of gas per 1 barrel of oil equivalent.

The estimated future revenue to be derived from the production and sale of the net proved reserves, as of December 31, 2021, of the properties evaluated using the guidelines established by the SEC is summarized as follows, expressed in thousands of dollars (M$):

	Proved Developed (M$)	Total Proved (M$)
Future Gross Revenue	249,046	1,092,170
Production and Ad Valorem Taxes	18,062	77,893
Operating Expenses	98,670	228,460
Capital and Abandonment Costs	2,187	265,843
Future Net Revenue	130,127	519,974
Present Worth at 10 Percent	78,674	215,929

Note: Future income taxes have not been taken into account in the preparation of these estimates.

While the oil and gas industry may be subject to regulatory changes from time to time that could affect an industry participant's ability to recover its reserves, we are not aware of any such governmental actions which would restrict the recovery of the December 31, 2021, estimated reserves.DeGolyer and MacNaughton is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1936. DeGolyer and MacNaughton does not have any financial interest, including stock ownership, in Abraxas. Our fees were not contingent on the results of our evaluation. This report has been prepared at the request of Abraxas. DeGolyer and MacNaughton has used all assumptions, data, procedures, and methods that it considers necessary and appropriate to prepare this report.

Submitted,

DeGOLYER and MacNAUGHTON
Texas Registered Engineering

Firm F-716**CERTIFICATE of QUALIFICATION**

I, Dilhan Ilk, Petroleum Engineer with DeGolyer and MacNaughton, 5001 Spring Valley Road, Suite 800 East, Dallas, Texas, 75244 U.S.A., hereby certify:

1. That I am a Senior Vice President with DeGolyer and MacNaughton, which firm did prepare this report of third party addressed to Abraxas dated February 4, 2022, and that I, as Senior Vice President, was responsible for the preparation of this report of third party.

2. That I attended Istanbul Technical University, and that I graduated with a Bachelor of Science degree in Petroleum Engineering in the year 2003, a Master of Science degree in Petroleum Engineering from Texas A&M University in 2005, and a Doctor of Philosophy degree in Petroleum Engineering from Texas A&M University in 2010; that I am a Registered Professional Engineer in the State of Texas; that I am a member of the Society of Petroleum Engineers; and that I have in excess of 11 years of experience in oil and gas reservoir studies and reserves evaluations.

Document And Entity Information - USD ($)	12 Months Ended Dec. 31, 2021	Mar. 18, 2022	Jun. 30, 2021
Document Information [Line Items]			
Entity Central Index Key	0000867665		
Entity Registrant Name	ABRAXAS PETROLEUM CORP		
Amendment Flag	false		
Current Fiscal Year End Date	--12-31		
Document Fiscal Period Focus	FY		
Document Fiscal Year Focus	2021		
Document Type	10-K		
Document Annual Report	true		
Document Period End Date	Dec. 31, 2021		
Document Transition Report	false		
Entity File Number	001-16071		
Entity Incorporation, State or Country Code	NV		
Entity Tax Identification Number	74-2584033		
Entity Address, Address Line One	18803 Meisner Drive		
Entity Address, City or Town	San Antonio		
Entity Address, State or Province	TX		
Entity Address, Postal Zip Code	78258		
City Area Code	210		
Local Phone Number	490-4788		
Title of 12(b) Security	Common Stock, par value $.01 per share		
Trading Symbol	AXAS		
Entity Well-known Seasoned Issuer	No		
Entity Voluntary Filers	No		
Entity Current Reporting Status	Yes		
Entity Interactive Data Current	Yes		
Entity Filer Category	Non-accelerated Filer		
Entity Small Business	true		
Entity Emerging Growth Company	false		
ICFR Auditor Attestation Flag	false		
Entity Shell Company	false		
Entity Public Float			$ 26,530,865
Entity Common Stock, Shares Outstanding		8,421,910	
Auditor Name	ADKF, P.C.		
Auditor Location	San Antonio, Texas		
Auditor Firm ID	297		

Consolidated Balance Sheets - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Current assets:		
Cash and cash equivalents	$ 10,034	$ 2,775
Accounts receivable:		
Joint owners, net	1,117	1,255
Oil and gas production sales	12,280	8,794
Other	150	0
Total accounts receivable	13,547	10,049
Derivative asset - short-term	0	9,639
Other current assets	498	1,588
Total current assets	24,079	24,051
Property and equipment		
Proved oil and gas properties, full cost method	1,165,707	1,167,333
Other property and equipment	39,337	39,456
Total	1,205,044	1,206,789
Less accumulated depreciation, depletion, amortization and impairment	(1,099,075)	(1,083,843)
Total property and equipment - net	105,969	122,946
Operating lease right-of-use assets	173	228
Derivative asset, long-term	0	10,281
Other assets	255	255
Total assets	130,476	157,761
Current liabilities:		
Accounts payable	4,678	6,074
Joint interest oil and gas production payable	13,347	8,795
Accrued interest	477	86
Other accrued liabilities	347	230
Derivative liabilities - short-term	442	480
Termination of derivative contracts	8,022	0
Right of use liability	40	53
Current maturities of long-term debt	212,688	202,751
Other current liabilities	0	850
Total current liabilities	240,041	219,319
Right of use liability	110	150
Future site restoration	4,708	7,360
Total liabilities	247,064	230,728
Commitments and contingencies (Note 8)		
Stockholders' Deficit		
Preferred stock, par value $0.01 per share - authorized 1,000,000 shares; - 0- shares issued and outstanding	0	0
Common stock, par value $0.01 per share, authorized 20,000,000 shares; 8,421,910 issued and outstanding at December 31, 2020 and 2021	84	84
Additional paid-in capital	430,422	429,476

Accumulated deficit	(547,094)	(502,527)
Total stockholders' deficit	(116,588)	(72,967)
Total liabilities and stockholders' deficit	130,476	157,761
Debt Instruments Excluding PPP Loan [Member]		
Current liabilities:		
Long-term debt - less current maturities	2,205	2,515
Paycheck Protection Program, CARES Act [Member]		
Current liabilities:		
Long-term debt - less current maturities	$ 0	$ 1,384

Consolidated Balance Sheets (Parentheticals) - $ / shares	Dec. 31, 2021	Dec. 31, 2020
Preferred stock, par value (in dollars per share)	$ 0.01	$ 0.01
Preferred stock, authorized (in shares)	1,000,000	1,000,000
Preferred stock, issued (in shares)	0	0
Preferred stock, outstanding (in shares)	0	0
Common stock, par value (in dollars per share)	$ 0.01	$ 0.01
Common stock, authorized (in shares)	20,000,000	20,000,000
Common stock, issued (in shares)	8,421,910	8,421,910
Common stock, outstanding (in shares)	8,421,910	8,421,910

Consolidated Statements of Operations - USD ($) shares in Thousands, $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Revenues:		
Other	$ 22	$ 59
Total Revenue	78,858	43,043
Operating costs and expenses		
Lease operating	17,914	16,458
Production and ad valorem taxes	6,223	4,632
Rig expense	478	762
Depreciation, depletion, amortization and accretion	15,643	24,846
Proved property impairment	0	186,980
General and administrative (including stock-based compensation of $946 and $1,312, respectively)	8,116	8,783
Total operating costs and expenses	48,374	242,461
Operating (loss) income	30,484	(199,418)
Other (income) expense:		
Interest income	(15)	(39)
Interest expense	35,773	21,281
Amortization of deferred financing fees	4,804	2,565
Deferred finance fees and warrant cancelation	4,212	0
(Gain) loss on derivative contracts	33,022	(42,880)
Gain on sale of non-oil and gas assets	(29)	0
Other	0	69
Total other (income) expense	75,051	(14,896)
(Loss) before income tax	(44,567)	(184,522)
Income tax (expense) benefit	0	0
Net loss	$ (44,567)	$ (184,522)
Net loss per common share - basic (in dollars per share)	$ (5.30)	$ (22.01)
Net loss per common share - diluted (in dollars per share)	$ (5.30)	$ (22.01)
Weighted average shares outstanding		
Basic (in shares)	8,408	8,382
Diluted (in shares)	8,408	8,382
Paycheck Protection Program, CARES Act [Member]		
Other (income) expense:		
Gain (loss) on debt extinguishment	$ (2,716)	$ 0
Second Lien Credit Facility [Member]		
Other (income) expense:		
Gain (loss) on debt extinguishment	0	4,108
Oil Revenues [Member]		
Revenues:		
Revenues	61,228	41,969
Gas Revenues [Member]		

Revenues:		
Revenues	8,656	586
Natural Gas Liquids Revenues [Member]		
Revenues:		
Revenues	$ 8,952	$ 429

Consolidated Statements of Operations (Parentheticals) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Stock-based compensation	$ 946	$ 1,312

Consolidated Statements of Stockholders' Equity - USD ($) $ in Thousands	Common Stock [Member]	Additional Paid-in Capital [Member]	Retained Earnings [Member]	Total
Balance (in shares) at Dec. 31, 2019	8,436,498			
Balance at Dec. 31, 2019	$ 84	$ 421,740	$ (318,005)	$ 103,819
Net loss	0	0	(184,522)	(184,522)
Warrant issued	0	6,424	0	6,424
Stock-based compensation	$ 0	1,312	0	1,312
Restricted stock issued, net of forfeitures (in shares)	(14,588)			
Restricted stock issued, net of forfeitures	$ 0	0	0	$ 0
Balance (in shares) at Dec. 31, 2020	8,421,910			8,421,910
Balance at Dec. 31, 2020	$ 84	429,476	(502,527)	$ (72,967)
Net loss	0		(44,567)	(44,567)
Stock-based compensation	$ 0	946	0	$ 946
Balance (in shares) at Dec. 31, 2021	8,421,910			8,421,910
Balance at Dec. 31, 2021	$ 84	$ 430,422	$ (547,094)	$ (116,588)

Consolidated Statements of Cash Flows - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Operating Activities:		
Net loss	$ (44,567)	$ (184,522)
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Loss (gain) on sale of non-oil and gas assets	(29)	0
Net loss (gain) on derivative contracts	33,022	(42,880)
Net cash settlements received (paid) on derivative contracts	(3,197)	16,006
Depreciation, depletion and amortization	15,312	24,432
Proved property impairment	0	186,980
Amortization of deferred financing fees and issuance discount	8,781	3,926
Non-cash financing fees and warrant cancellation	194	0
Accretion of future site restoration	330	414
Plugging cost	(342)	(236)
Non-cash interest	24,705	12,695
Non-cash hedge termination	9,943	0
Stock-based compensation	946	1,312
Changes in operating assets and liabilities:		
Accounts receivable	(3,498)	9,596
Other assets	(8,851)	(394)
Accounts payable	3,151	(15,304)
Accrued expenses and other	(765)	(148)
Net cash provided by operating activities	32,419	15,985
Investing Activities		
Capital expenditures, including purchase and development of properties	(887)	(12,557)
Proceeds from the sale of oil and gas properties	141	0
Proceeds from the sale of non-oil and gas assets	228	0
Net cash (used) in investing activities	(518)	(12,557)
Financing Activities		
Payments of long-term borrowings	(25,816)	(9,059)
Deferred financing fees	(158)	(978)
Net cash (used) in financing activities	(24,642)	(653)
Increase in cash and cash equivalents	7,259	2,775
Cash and cash equivalents at beginning of period	2,775	0
Cash and cash equivalents at end of period	10,034	2,775
Supplemental disclosure of cash flow information:		
Interest paid	6,463	7,174
Income tax paid	0	0
Non-cash investing and financing activities		
Change in asset retirement obligation cost and liabilities	204	(22)
Asset retirement obligations associated with dispositions	(2,845)	(216)
Change in capital expenditures included in accounts payable	5	(7,157)

Second Lien Credit Facility [Member]		
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Gain (loss) on debt extinguishment	0	4,108
Paycheck Protection Program, CARES Act [Member]		
Adjustments to reconcile net (loss) to net cash provided by operating activities:		
Gain (loss) on debt extinguishment	(2,716)	0
Financing Activities		
Proceeds from long-term borrowings	1,332	1,384
First Lien Credit Facility [Member]		
Financing Activities		
Proceeds from long-term borrowings	$ 0	$ 8,000

Note 1 - Organization and Significant Accounting Policies	12 Months Ended Dec. 31, 2021
Notes to Financial Statements	
Organization, Consolidation and Presentation of Financial Statements Disclosure and Significant Accounting Policies [Text Block]	(see below)

1. Organization and Significant Accounting Policies

Nature of Operations

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States. Our oil and gas assets are located primarily in two operating regions in the United States: the Rocky Mountains and Permian/Delaware Basin.

The terms “Abraxas,” “Abraxas Petroleum,” “we,” “us,” “our” or the “Company” refer to Abraxas Petroleum Corporation and all of its subsidiaries, including Raven Drilling LLC (“Raven Drilling”).

Rig Accounting

In accordance with SEC Regulation S-X, no income is recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates holds an ownership, or other economic interest. Any income not recognized as a result of this limitation is credited to the full cost pool and recognized through lower amortization as reserves are produced. During 2020 and 2021 the drilling rig was idle, accordingly the cost of the rig was charged to the statement of operations.

Use of Estimates

The consolidated financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in the United States of America (“GAAP”). The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

The most significant estimates pertain to proved oil, gas and NGL reserves and related cash flow estimates used in impairment tests of oil and gas properties, the fair value of assets and liabilities acquired in business combinations, derivative contracts, the provision for income taxes including uncertain tax positions, stock based compensation, asset retirement obligations, accrued oil and gas revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates.

The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, differentials, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, our ability to fund estimated development cost, prevailing oil and gas prices and other factors, many of which are beyond our control.

Reclassifications

Certain reclassifications have been made to the prior year financial statements to conform to the current period presentation. These reclassifications were to share and per share data related to the 1 for 20 reverse stock split effective October 19, 2020 and had no effect on our previously reported results of operations.

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables and derivative contracts. Accounts receivable are generally from companies with significant oil and gas marketing or operating activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers. The counterparties to our derivative contracts are the same financial institutions from which we have outstanding debt; accordingly, we believe our exposure to credit risk to these counterparties is currently mitigated in part by this, as well as the current overall financial condition of the counterparties.

The Company maintains any cash and cash equivalents in excess of federally insured limits in prominent financial institutions considered by the Company to be of high credit quality.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits and short-term investments with original maturities of three months or less.

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $0.1 million at December 31, 2020 and 2021 . The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of oil and gas with all of the Company's operational activities being conducted in the U.S. The Company's current operational activities and the Company's consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long lived assets located outside the U.S.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, certain direct costs and indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated future net revenues are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. The Company applies the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. The impairment calculations do not consider the impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. As of December 31, 2020, our capitalized cost of oil and gas properties exceeded the future net revenue from our estimated proved reserves resulting in the recognition of an impairment of $187.0 million. As of December 31, 2021, our capitalized cost of oil and gas properties did not exceed the future net revenue from our estimated proved reserves.

Other Property and Equipment

Other property and equipment are recorded at cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and improvements are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

Estimates of Proved Oil and Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved reserve information included in this report was based on studies performed by our independent petroleum engineers assisted by the engineering and operations departments of Abraxas. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may cause material revisions to the estimate.

In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on the average of oil and gas prices based on the unweighted average 12 month first-day-of-month pricing. Future prices and costs may be materially higher or lower than these prices and costs which would impact the estimated value of our reserves.

The estimates of proved reserves materially impact depreciation, depletion and amortization, or DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields.

Derivative Instruments and Hedging Activities

The Company enters into agreements to hedge the risk of future oil and gas price fluctuations. Such agreements are typically in the form of fixed price commodity and basis swaps, which limit the impact of price fluctuations with respect to the Company's sale of oil and gas. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions could arise where actual production is less than estimated which could result in over hedged volumes.

All derivative instruments are recorded on the Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The derivative instruments the Company utilizes are based on index prices that may and often do differ from the actual oil and gas prices realized in its operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for hedge accounting rules as prescribed by Accounting Standards Codification ("ASC") 815. Accordingly, the Company does not account for its derivative instruments as cash flow hedges for financial reporting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in net gains (losses) on commodity derivative contracts in the Consolidated Statements of Operations.

Fair Value of Financial Instruments

The Company includes fair value information in the notes to consolidated financial statements when the fair value of its financial instruments is materially different from the carrying value. The carrying value of those financial instruments that are classified as current, except for derivative instruments, approximates fair value because of the short maturity of these instruments. For noncurrent financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments.

Share-Based Payments

Options granted are valued at the date of grant and expense is recognized over the vesting period. The Company currently utilizes a standard option pricing model (Black-Scholes) to measure the fair value of stock options granted to employees and directors. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such restricted stock is determined using the market price on the grant date and expense is recorded over the vesting period. For the years ended December 31, 2020 and 2021, stock-based compensation was approximately $1.3 million and $0.9 million, respectively.

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and we amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements. Each year, the Company reviews, and to the extent necessary, revises its asset retirement obligation estimates.

The following table (in thousands) summarizes changes in the Company's future site restoration obligations during the two years ended December 31:

	2020	2021
Beginning future site restoration obligation	$ 7,420	$ 7,360
New wells placed on production and other	43	1
Deletions related to property disposals	(216)	(2,845)
Deletions related to plugging costs	(235)	(342)
Accretion expense and other	414	330

Revisions and other	(66)	204
Ending future site restoration obligation	$ 7,360	$ 4,708

Revenue Recognition and Major Purchasers

The Company recognizes oil and gas revenue from its interest in producing wells as oil and gas is sold from those wells, net of royalties, control of the product has transferred to the purchaser and collectability is reasonably assured.

During 2020 four purchasers accounted for 73% of oil and gas revenues. During 2021, four purchasers accounted for 83% of oil and gas revenues.

Deferred Financing Fees

Deferred financing fees are being amortized on the effective yield basis over the term of the related debt.

Income Taxes

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to be in effect with respect to taxable income in the years in which those temporary differences are expected to be recovered or settled. Uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, we have established a valuation allowance of $124.08 million for deferred tax assets at December 31, 2021.

Accounting for Uncertainty in Income Taxes

Evaluation of a tax position is a two-step process. The first step is to determine whether it is more-likely-than-not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation based on the technical merits of that position. The second step is to measure a tax position that meets the more-likely-than-not threshold to determine the amount of benefit to be recognized in the financial statements. A tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

Tax positions that previously failed to meet the more-likely-than-not recognition threshold should be recognized in the first subsequent period in which the threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not criteria should be de-recognized in the first subsequent reporting period in which the threshold is no longer met. Penalties and interest are classified as income tax expense. The Company had no uncertain income tax positions as of December 31, 2021.

Adoption of New Accounting Standards

In March 2020, the FASB issued ASU No. 2020-04, “Reference Rate Reform (Topic 840): Facilitation of the Effects of Reference Rate Reform on Financial Reporting” (“ASU 2020-04”), which provides companies with optional guidance to ease the potential accounting burden associated with transitioning away from reference rates (e.g., London Interbank Offered Rate (“LIBOR”)) that are expected to be discontinued. ASU 2020-04 allows, among other things, certain contract modifications, such as those within the scope of Topic 470 on debt, to be accounted as a continuation of the existing contract. This ASU was effective upon the issuance and its optional relief can be applied through December 31, 2022. The Company will consider this optional guidance prospectively, if applicable.

In May 2020, the SEC adopted final rules that amend the financial statement requirements for significant business acquisitions and dispositions. Among other changes, the final rules modify the significance tests and improve the disclosure requirements for acquired or to be acquired businesses and related pro forma financial information, the periods those financial statements must cover, and the form and content of the pro forma financial information. The final rules do not modify requirements for the acquisition and disposition of significant amounts of assets that do not constitute a business. The final rules are effective January 1, 2021, but earlier compliance is permitted. The Company will consider these final rules and update its disclosures, as applicable.

Note 2 - Revenue From Contracts With Customers	12 Months Ended
	Dec. 31, 2021
Notes to Financial Statements	
Revenue from Contract with Customer [Text Block]	**2. Revenue from Contracts with Customers**

Revenue Recognition

Sales of oil, gas and NGL are recognized at the point in time when control of the product is transferred to the customer and collectability is reasonably assured. The Company's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, physical location, quality of the oil or gas, and prevailing supply and demand conditions. As a result, the price of the oil, gas and NGL fluctuates to remain competitive with other available oil, gas and NGL supplies in the market. The Company believes that the pricing provisions of our oil, gas and NGL contracts are customary in the industry.

Oil sales

The Company's oil sales contracts are generally structured such that it sells its oil production to a purchaser at a contractually specified delivery point at or near the wellhead. The crude oil production is priced on the delivery date based upon prevailing index prices less certain deductions related to oil quality, physical location and transportation costs incurred by the purchaser subsequent to delivery. The Company recognizes revenue when control transfers to the purchaser upon delivery at or near the wellhead at the net price received from the purchaser. Payment terms as customarily and normally paid on the twentieth day of the month following production.

Gas and NGL Sales

Under the Company's gas processing contracts, it delivers wet gas to a midstream processing entity at the wellhead or the inlet of the midstream processing entity's system. There are no performance obligations related to these contracts. The midstream processing entity processes the gas and remits proceeds to the Company based upon either (i) the resulting sales price of NGL and residue gas received by the midstream processing entity from third party customers or (ii) the prevailing index prices for NGL and residue gas in the month of delivery to the midstream processing entity. Gathering, processing, transportation and other expenses incurred by the midstream processing entity are typically deducted from the proceeds that the Company receives.

In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. With respect to the Company's gas purchase contracts, the Company has concluded that it is the agent, and thus, the midstream processing entity is its customer. Accordingly, the Company recognizes revenue upon delivery to the midstream processing entity based on the net amount of the proceeds received from the midstream processing entity.

Imbalances

The Company had no material gas imbalances at December 31, 2020 and 2021.

Disaggregation of Revenue

The Company is focused on the development of oil and natural gas properties primarily located in the following operating regions in the United States: (i) the Permian/Delaware Basin and (ii) Rocky Mountain. Revenue attributable to each of those regions is disaggregated in the table below.

	Years Ended December 31,					
	2020			2021		
	Oil	Gas	NGL	Oil	Gas	NGL
Operating Region						
Permian/ Delaware Basin	$ 22,891	$ 335	$ 163	$ 32,666	$ 4,474	$ 2,181
Rocky Mountain (1)	$ 19,078	$ 251	$ 266	$ 28,562	$ 4,182	$ 6,771

(1) All Rocky Mountain assets were sold January 3, 2022.

Significant Judgments

Principal versus agent

The Company engages in various types of transactions in which midstream entities process the Company's gas and subsequently market resulting NGL and residue gas to third-party customers on behalf of the Company, such as the Company’s percentage-of-proceeds and gas purchase contracts. These types of transactions require judgment to determine whether we are the principal or the agent in the contract and, as a result, whether revenues are recorded gross or net.

Transaction price allocated to remaining performance obligations

A significant number of the Company’s product sales are short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC Topic 606-10-50-14 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC Topic 606-10-50-14(a) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Contract balances

Under the Company’s product sales contracts, the Company is entitled to payment from purchasers once its performance obligations have been satisfied upon delivery of the product, at which point payment is unconditional. The Company records invoiced amounts as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheet.

To the extent actual volumes and prices of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and also recorded as “Accounts receivable - Oil and gas production sales” in the accompanying condensed consolidated balance sheets. In this scenario, payment is also unconditional, as the Company has satisfied its performance obligations through delivery of the relevant product. As a result, the Company has concluded that its product sales do not give rise to contract assets or liabilities under ASU 2014-09. At December 31, 2020 and December 31, 2021, our receivables from contracts with customers were $8.8 million and $12.3 million, respectively.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain gas and NGL sales may not be received for 30 to 60 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the midstream purchaser and the price that will be received for the sale of the product. Additionally, to the extent actual volumes and prices of oil are unavailable for a given reporting period because of timing or information not received from third party purchasers, the expected sales volumes and prices for those barrels of oil are also estimated.

The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the year ended December 31, 2021, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Note 3 - Reverse Stock Split	12 Months Ended Dec. 31, 2021
Notes to Financial Statements	
Reverse Stock Split [Text Block]	**3. Reverse Stock Split** On October 19, 2020 the Company effected a 1-for-20 reverse stock split of its issued and outstanding shares of common stock, $0.01 par value (the " Reverse Stock Split"). The Company effected the Reverse Stock Split pursuant to the Company's filing of a Certificate of Change with the Secretary of State of the State of Nevada on September 29, 2020. Under Nevada law, no amendment to the Company's Articles of Incorporation was required in connection with the Reverse Stock Split. The Company was authorized to issue 400,000,000 shares of Common Stock. As a result of the Reverse Stock Split, the Company will be authorized to issue 20,000,000 shares of Common Stock. As a result of the Reverse Stock Split, 168,069,305 outstanding shares of the Company's common stock were exchanged for approximately 8,453,466 shares of the Company's common stock (subject to adjustment due to the effect of rounding fractional shares into whole shares). Under the terms of the Reverse Stock Split, fractional shares issuable to stockholders were rounded up to the nearest whole share. The Reverse Stock Split will not have any effect on the stated par value of the Common Stock. All per share amounts and number of shares in the condensed consolidated financial statements and related notes have been retroactively restated to reflect the Reverse Stock Split, resulting in the transfer of $1.6 million from common stock to additional paid in capital at September 30, 2020 and December 31, 2019. Additionally on the effective date of the Reverse Stock Split, all options, warrants and other convertible securities of the Company outstanding immediately prior to the Reverse Stock Split were adjusted by dividing the number of shares of common stock into which the options, warrants and other convertible securities are exercisable or convertible by 20, and multiplying the exercise or conversion price thereof by 20, all in accordance with the terms of the plans, agreements or arrangements governing such options, warrants and other convertible securities and subject to rounding to the nearest whole share.

Note 4 - Long-term Debt	12 Months Ended Dec. 31, 2021

Notes to Financial Statements

Long-term Debt [Text Block]

4. Long-Term Debt

The following sections regarding the First Lien Credit Facility and Second Lien Credit Facility are qualified in their entirety by the disclosure contained in Note 14. "Subsequent Events", Restructuring, which is expressly incorporated in the sections above. Due to certain of covenant violations under our credit facilities as of December 31, 2020 and 2021, all of the debt related to our credit facilities has been classified as current liabilities. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

The following is a description of the Company's debt as of December 31, 2020 and 2021, respectively:

	Years Ended December 31,	
	2020	2021
	(In thousands)	
First Lien Credit Facility	$ 95,000	$ 71,400
Second Lien Credit Facility	112,695	134,907
Exit fee - Second Lien Credit Facility	10,000	10,000
Real estate lien note	2,810	2,515
	220,505	218,822
Less current maturities	(202,751)	(212,688)
	17,754	6,134
Deferred financing fees and debt issuance cost - net	(15,239)	(3,929)
Total long-term debt, net of deferred financing fees and debt issuance costs	$ 2,515	$ 2,205

Maturities of long-term debt are as follows:

Years ending December 31, (In thousands)	
2022	$216,617
2023	2,205
2024	
2025	-
2026	-
Thereafter	-
Total	$218,822

First Lien Credit Facility

The Company had a senior secured First Lien Credit Facility with Société Générale, as administrative agent and issuing lender, and certain other lenders. As of December 31, 2021, $71.4 million was outstanding under the First Lien Credit Facility.

Outstanding amounts under the First Lien Credit Facility accrued interest at a rate per annum equal to (a)(i) for borrowings that we elected to accrue interest at the reference rate at the greater of (x) the reference rate announced from time to time by Société Générale, (y) the federal funds rate plus 0.5%, and (z) daily one-month LIBOR plus, in each case, 1.5%-2.5%, depending on the utilization of the borrowing base, and (ii) for borrowings that we elected to accrue interest at the Eurodollar rate, LIBOR plus 2.5%-3.5% depending on the utilization of the borrowing base, and (b) at any time an event of default existed, 3.0% plus the amounts set forth above. At December 31, 2021, the interest rate on the First Lien Credit Facility was approximately 8.75%.

Subject to earlier termination rights and events of default, the stated maturity date of the First Lien Credit Facility was May 16, 2022. Interest was payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. The Company was permitted to terminate the First Lien Credit Facility and was able, from time to time, to permanently reduce the lenders' aggregate commitment under the First Lien Credit Facility in compliance with certain notice and dollar increment requirements.

Each of the Company's subsidiaries guaranteed our obligations under the First Lien Credit Facility on a senior secured basis. Obligations under the First Lien Credit Facility were secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of the Company and its subsidiary guarantors' material property and assets. As of December 30, 2020, the collateral was required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company's PDP reserves.

Under the amended First Lien Credit Facility, the Company was subject to customary covenants, including financial covenants and reporting covenants. The amendment to the First Lien Credit Facility dated June 25, 2020 (the "1L Amendment") modified certain provisions of the First Lien Credit Facility, including (i) the addition of monthly mandatory prepayments from excess cash (defined as available cash minus certain cash set-asides and a $3.0 million working capital reserve) with corresponding reductions to the borrowing base; (ii) the elimination of scheduled redeterminations (which were previously made every six months) and interim redeterminations (which were previously made at the request of the lenders no more than once in the six month period between scheduled redeterminations) of the borrowing base; (iii) the replacement of total debt leverage ratio and minimum asset ratio covenants with a first lien debt leverage ratio covenant (comparing the outstanding debt of the First Lien Credit Facility to the consolidated EBITDAX of the Company and requiring that the ratio not exceed 2.75 to 1.00 as of the last day of each fiscal quarter) and a minimum first lien asset coverage ratio covenant (comparing the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedge agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the outstanding debt of the First Lien Credit Facility and requiring that the ratio exceed 1.15 to 1.00 as of the last day of each fiscal quarter ending on or before December 31, 2020, and 1.25 to 1.00 for fiscal quarters ending thereafter); (iv) the elimination of current ratio and interest coverage ratio covenants; (v) additional restrictions on (A) capital expenditures (limiting capital expenditures to $3.0 million in any four fiscal quarter period (commencing with the four fiscal quarter period ended June 30, 2020 and calculated on an annualized basis for the 1, 2 and 3 quarter periods ended on June 30, 2020, September 30, 2020 and December 31, 2020, respectively, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt and capital expenditures made when (1) the first lien asset coverage ratio is at least 1.60 to 1.00, (2) the Company is in compliance with the first lien leverage ratio, (3) the amounts outstanding under the First Lien Credit Facility are less $50.0 million, (4) no default exists under the First Lien Credit Facility and (5) and all representations and warranties in the First Lien Credit Facility and the related credit documents are true and correct in all material respects), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company may make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.9 million for the four fiscal quarter period ended December 31, 2020, and $6.5 million for the fiscal quarter from March 31, 2021 through December 31, 2021 and $5.0 million thereafter; in all cases, general and administrative expense excluded up to $1.0 million in certain legal and professional fees; and (vi) permission for up to an additional $25.0 million in structurally subordinated debt to finance capital expenditures. Under the 1L Amendment, the borrowing base was adjusted to $102.0 million. Prior to retirement, the borrowing base was reduced by any mandatory prepayments from excess cash flow.

The First Lien Credit Facility contained a number of covenants that, among other things, restricted our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an “arm’s length” basis;
- make any change in the principal nature of our business; and
- permit a change in control

The First Lien Credit Facility also contained customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

As of December 31, 2021, we were not in compliance with the financial covenants under the First Lien Credit Facility, as amended.

In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 “Subsequent Events.”

Second Lien Credit Facility

On November 13, 2019, we entered into the Term Loan Credit Agreement, with Angelo Gordon Energy Servicer, LLC, as administrative agent, and certain other lenders party thereto, which we refer to as the Second Lien Credit Facility. The Second Lien Credit facility was amended on June 25, 2020. The Second Lien Credit Facility had a maximum commitment of $100.0 million. On November 13, 2019, $95.0 million of the net proceeds obtained from the Second Lien Credit Facility were used to permanently reduce the borrowings outstanding on the First Lien Credit Facility. As of December 31, 2021, the outstanding balance on the Second Lien Credit Facility was $144.9 million, which included a $10.0 million exit fee. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 “Subsequent Events.”

The stated maturity date of the Second Lien Credit Facility was November 13, 2022. Prior to the latest amendments of the Second Lien Credit Facility, accrued interest was payable quarterly on reference rate loans and at the end of each three-month interest period on Eurodollar loans. We were permitted to prepay the loans in whole or in part, in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries had guaranteed our obligations under the Second Lien Credit Facility. Obligations under the Second Lien Credit Facility were secured by a first priority perfected security interest, subject to certain permitted liens, including those securing the indebtedness under the First Lien Credit Facility to the extent permitted by the Intercreditor Agreement, of even date with the Second Lien Credit Facility, among us, our subsidiaries, Angelo Gordon Energy Servicer, LLC and Société Générale, in all of our subsidiary guarantors’ material property and assets. As of December 31, 2020, the collateral was required to include properties comprising at least 90% of the PV-9 of the Company's proven reserves and 95% of the PV-9 of the Company’s PDP reserves.

Under the amended Second Lien Credit Facility, the Company was subject to customary covenants, including financial covenants and reporting covenants. The amendment to the Second Lien Credit Facility dated June 25, 2020 (the “2L Amendment”) modified certain provisions of the Second Lien Credit Facility, including (i) a requirement that, while the obligations under the First Lien Credit Facility were outstanding, scheduled payments of accrued interest under the Second Lien Credit Facility would be paid in the form of capitalized interest; (ii) an increase in the interest rate by 200bps for interest payable in cash and 500bps for interest payable in kind; (iii) modification of the minimum asset ratio covenant to be the sum of, without duplication, (A) the PV-15 of producing and developed proven reserves of the Company, (B) the PV-9 of the Company's hydrocarbon hedge agreements and (C) the PV-15 of proved reserves of the Company classified as "drilled uncompleted" (up to 20% of the sum of (A), (B) and (C)) to the total outstanding debt of the Company and requiring that the ratio not exceed 1.45 to 1.00 as of the last day of each fiscal quarter ending between September 30, 2021 to December 31, 2021, and 1.55 to 1.00 for fiscal quarters ending thereafter); (iv) modification of the total leverage ratio covenant to set the first test date to occur on September 30, 2021; (v) modification of the current ratio to eliminate the exclusion of certain valuation accounts associated with hedge contracts from current assets and from current liabilities, (vi) additional restrictions on (A) capital expenditures (limiting capital expenditures to those expenditures set forth in a plan of development approved by Angelo Gordon Energy Servicer, LLC, subject to certain exceptions, including capital expenditures financed with the proceeds of newly permitted, structurally subordinated debt), (B) outstanding accounts payable (limiting all outstanding and undisputed accounts payable to $7.5 million, undisputed accounts payable outstanding for more than 60 days to $2.0 million and undisputed accounts payable outstanding for more than 90 days to $1.0 million and (C) general and administrative expenses (limiting cash general and administrative expenses the Company could make or become legally obligated to make in any four fiscal quarter period to $9.0 million for the four fiscal quarter period ended June 30, 2020, $8.25 million for the four fiscal quarter period ended September 30, 2020, $6.5 million for fiscal quarter period from March 31, 2021 through December 31, 2021 and $5.0 million thereafter.

The Second Lien Credit Facility contained a number of covenants that, among other things, restricted our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- pay dividends or make other distributions on capital stock or make other restricted payments;
- engage in transactions with affiliates other than on an "arm's length" basis;
- make any change in the principal nature of our business; and
- permit a change of control

The Second Lien Credit Facility also contained customary events of default, including nonpayment of principal or interest, violation of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Events of default occurred under the Second Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the Second Lien Credit Facility, (iii) the failure of the Company to meet certain hedging requirements, (iv) the Company's inability to comply with the total leverage ratio for the fiscal quarter ended September 30, 2021, (v) the Company's inability to comply with minimum asset coverage ratio for the fiscal quarter ended September 30, 2021, and (vi) certain cross-defaults that occurred, or could have occurred, as a result of the occurrence of events of default under the First Lien Credit Facility and corresponding cross-defaults or similar termination events under our hedging contracts. Additional events of default occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended.

On April 16, 2021, we received a Notice of Default and Reservation of Rights (the "Notice of Default") from Angelo Gordon stating that we defaulted under the Second Lien Credit

Facility, and that, as a result, the lenders accelerated our obligations due thereunder and reserved their rights to pursue additional remedies in the future.

The Notice of Default described certain events of default that occurred under the Second Lien Credit Facility as a result of (i) our failure to file timely our Form 10-K for the fiscal year ended December 31, 2020, (ii) our failure to timely deliver audited financial statements without a “going concern” or like qualification for the fiscal year ended December 31, 2020, and (iii) other defaults under our revolving credit facility.

The Notice of Default declared that our obligations under the Second Lien Credit Facility are immediately due and payable, in each case without presentment, demand, protest or other requirements of any kind, and began to bear interest at the rate applicable to such amount under the Second Lien Credit Facility, plus an additional 3%. Additionally, the administrative agent and the lenders reserved their right to exercise further rights, powers and remedies under the Second Lien Credit Facility, at any time or from time to time, with respect to any of the events of default described above.

In connection with the amendment to the Second Lien Credit Facility on June 25, 2020, the Company entered into an Exit Fee and Warrant Agreement subject to NASDAQ approval for the issuance of the issuance of certain warrants. This agreement was finalized on August 11, 2020 at which time the Company issued a warrant to the lender to purchase a total of 33,445,792 shares of common stock at an exercise price of $0.01 per share. On October 19, 2020, the Company effected a reverse stock split of the Company’s authorized, issued and outstanding shares of common stock at a ratio of 1-for-20, thus the warrant was adjusted to provide that the lender may purchase a total of 1,672,290 shares of common stock at an exercise price of $0.20 per share. The warrant was exercisable immediately in whole or in part, on or before five years from the issuance date. The fair value of the warrant and exit fee were recorded as debt issuance costs, presented in the consolidated balance sheets as a deduction from the carrying amount of the note payable, and were being amortized over the loan term. The exit fee was due and payable in cash on the earliest to occur of maturity of the obligation under the Second Lien Credit Agreement or the earlier acceleration or payment in full of the same. The 2L Amendment, including the impact of the Exit Fee and Warrant Agreement finalized on August 11, 2020, resulted in the 2L Amendment meeting the criteria of debt extinguishment under the guidance of *ASC 470: Debt*. Accordingly, all debt issuance cost, including the original discount, of the original Second Lien Credit Facility, were charged to debt extinguishment loss in the accompanying Condensed Consolidated Statement of Operation in the amount of $4.1 million. Subsequently, pursuant to a waiver letter dated November 22, 2021 from AGEF to Abraxas, AGEF waived, relinquished, and abandoned all of its rights, title, and interest to the Warrant and any Common Stock underlying the Warrant for no consideration. The Company recorded a loss on the cancellation of the Warrant of approximately $2.5 million.

Real Estate Lien Note

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The outstanding principal accrues interest at a fixed rate of 4.9%. The note is payable in monthly installments of principal and interest in the amount of $35,672. The maturity date of the note is July 20, 2023. As of December 31, 2020, and 2021, $2.8 million and $2.5 million, respectively, were outstanding on the note.

Note 5 - Property and Equipment	12 Months Ended Dec. 31, 2021
Notes to Financial Statements	
Property, Plant and Equipment Disclosure [Text Block]	**5. Property and Equipment**

The major components of property and equipment, at cost, are as follows:

	Estimated Useful life Years	December 31, 2020	December 31, 2021
		(In thousands)	
Oil and gas properties (1)	-	$ 1,167,333	$ 1,165,707
Equipment and other	3-39	15,348	15,257
Drilling rig	15	24,108	24,080
		1,206,789	1,205,044
Accumulated depreciation, depletion, amortization and impairment		(1,083,843)	(1,099,075)
Net Property and Equipment		$ 122,946	$ 105,969

(1) Oil and gas properties are amortized utilizing the units of production method.

Note 6 - Stock-based Compensation and Option Plans	12 Months Ended
	Dec. 31, 2021
Notes to Financial Statements	
Share-based Payment Arrangement [Text Block]	

6. Stock-Based Compensation and Option Plans

The Company's Amended and Restated 2005 Employee Long-Term Equity Incentive Plan reserves 1,683,639 shares of Abraxas common stock, subject to adjustment following certain events. Awards may be in options or shares of restricted stock. Options have a term not to exceed 10 years. Options issued under this plan vest according to a vesting schedule as determined by the compensation committee of the Company's board of directors. Vesting may occur upon (1) the attainment of one or more performance goals or targets established by the committee, (2) the optionee's continued employment or service for a specified period of time, (3) the occurrence of any event or the satisfaction of any other condition specified by the committee, or (4) a combination of any of the foregoing.

Stock Options

The Company grants options to its officers, directors, and other employees under various stock option and incentive plans. There were no options granted in 2020 or 2021

The following table is a summary of the Company's stock option activity for the three years ended December 31:

	Options (000s)	Weighted average exercise price	Weighted average remaining life	Intrinsic value per share
Options outstanding December 31, 2019	297	$ 49.41		
Forfeited/Expired	(101)	48.96		
Options outstanding December 31, 2020	196	$ 49.69		
Forfeited/Expired	(141)	48.11		
Options outstanding December 31, 2021	55	53.79	3.3	$ 0.00
Exercisable at end of year	55	53.79	3.3	$ 0.00

Other information pertaining to the Company's stock option activity for the three years ended December 31:

	2020	2021
Weighted average grant date fair value of stock options granted (per share)	$ -	$ -
Total fair value of options vested (000's)	$ 275	$ -
Total intrinsic value of options exercised (000's)	$ -	$ -

As of December 31, 2021, there was no compensation cost related to non-vested awards. For the years ended December 31, 2020, we recognized $0.1 million in stock based-based compensation expense relating to options. No expense was recognized in 2021.

The following table represents the range of stock option prices and the weighted average remaining life of outstanding options as of December 31, 2021:

	Outstanding Options			Exercisable		
Range of stock option prices	Number Outstanding	Weighted average remaining life	Weighted average exercise price	Number Outstanding	Weighted average remaining life	Weighted average exercise price
19.40-29.99	12,700	2.9	$ 22.61	12,700	2.9	$ 22.61

30.00-39.99	5,350	5.4	$ 37.47	5,350	5.4	$ 37.47
40.00-49.99	6,228	1.4	$ 47.79	6,228	1.4	$ 47.79
50.00-59.99	8,900	4.2	$ 57.16	8,900	4.2	$ 57.16
60.00-69.99	7,594	2.2	$ 63.24	7,594	2.2	$ 63.24
70.00-79.99	6,500	2.6	$ 73.57	6,500	2.6	$ 73.57
80.00-89.99	1,500	5.5	$ 86.40	1,500	5.5	$ 86.40
90.00-99.99	3,000	5.9	$ 90.10	3,000	5.9	$ 890.10
100.00-125.60	2,450	2.3	$ 107.97	2,450	2.3	$ 107.67
	54,222	3.3	$ 53.79	54,222	3.3	$ 53.79

Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date. Compensation expense is recorded over the applicable restricted stock vesting periods. As of December 31, 2021, the total compensation cost related to non-vested awards not yet recognized was approximately $0.1 million, which will be recognized in the first quarter of 2022. For the years ended December 31, 2020 and 2021, we recognized $0.9 million and $0.6 million, respectively, in stock-based compensation expense related to restricted stock awards.

The following table is a summary of the Company's restricted stock activity for the three years ended December 31, 2021:

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2019	89	$ 31.67
Granted	-	-
Vested/Released	(33)	32.11
Forfeited/Expired	(15)	31.52
Unvested December 31, 2020	41	$ 31.37
Granted	-	-
Vested/Released	(24)	33.23
Forfeited/Expired	(3)	32.07
Unvested December 31, 2021	14	$ 27.97

Performance Based Restricted Stock Awards

Effective on April 1, 2018, the Company issued performance-based shares of restricted stock to certain officers and employees under the Abraxas Petroleum Corporation Amended and Restated 2005 Employee Long-Term Equity Incentive Plan. The shares will vest over a three year period upon the achievement of performance goals based on the Company's Total Shareholder Return ("TSR") as compared to a peer group of companies. The number of shares which would vest depends upon the rank of the Company's TSR as compared to the peer group at the end of the three-year vesting period, and can range from zero percent of the initial grant up to 200% of the initial grant. No shares vested in 2020 or 2021 due to not achieving the performance goals.

The table below provides a summary of Performance Based Restricted Stock as of the date indicated (shares in thousands):

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2019	57	33.86
Granted	-	-
Vested/Released	-	-
Forfeited	(13)	34.29
Unvested December 31, 2020	44	$ 33.73
Granted	-	-

Vested/Released	-		-
Forfeited	(16)		45.73
Unvested December 31, 2021	28	$	26.80

Compensation expense associated with the performance based restricted stock is based on the grant date fair value of a single share as determined using a Monte Carlo Simulation model which utilizes a stochastic process to create a range of potential future outcomes given a variety of inputs. As the Compensation Committee intends to settle the performance based restricted stock awards with shares of the Company's common stock, the awards are accounted for as equity awards and the expense is calculated on the grant date assuming a 100% target payout and amortized over the life of the awards.

As of December 31, 2021, the total compensation cost related to non-vested awards not yet recognized was approximately $0.1 million, which will be recognized in the first quarter of 2022. For each of the years ended December 31, 2020 and 2021, we recognized $0.2 million in stock-based compensation expense related to performance based restricted stock awards.

Director Stock Awards

The 2005 Directors Plan (as amended and restated) reserves 70,000 shares of Abraxas common stock, subject to adjustment following certain events. The 2005 Directors Plan provides that each year, at the first regular meeting of the board of directors immediately following Abraxas' annual stockholder's meeting, each non-employee director shall be granted or issued awards restricted stock with a value at the date of the grant of $12,000, for participation in board and committee meetings during the previous calendar year. This grant did not take place in 2020.

The maximum annual award for any one person is 1,250 shares of Abraxas common stock or options for common stock. If options, as opposed to shares, are awarded, the exercise price shall be no less than 100% of the fair market value on the date of the award while the option terms and vesting schedules are at the discretion of the committee.

At December 31, 2021, the Company had approximately 1.9 million shares reserved, under its Employee and Directors plans, for future issuance for conversion of its stock options, and incentive plans for the Company's directors, employees and consultants.

Note 7 - Income Taxes	12 Months Ended Dec. 31, 2021
[Notes to Financial Statements]	
Income Tax Disclosure [Text Block]	

7. Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

	As of December 31,	
	2020	2021
	(In thousands)	
Deferred tax liabilities:		
Hedge contracts	$ 4,299	$ -
Other	2,137	2,855
Total deferred tax liabilities	6,436	2,855
Deferred tax assets:		
US full cost pool	$ 35,500	24,464
Depletion carryforward	461	470
U.S. net operating loss carryforward	84,927	96,120
Alternative minimum tax credit	-	-
Hedge contracts	-	100
Interest disallowed	2,818	5,781
Total deferred tax assets	123,706	126,935
Valuation allowance for deferred tax assets	(117,270)	(124,080)
Net deferred tax assets	6,436	2,855
Net deferred tax	$ -	$ -

Significant components of the provision (benefit) for income taxes are as follows:

	Years Ended December 31,	
	2020	2021
	(In thousands)	
Current:		
Federal	$ -	$ -
State	-	-
	$ -	$ -
Deferred:		
Federal	$ -	$ -
	$ -	$ -

At December 31, 2021, the Company had, $245.20 million of pre 2018 NOLs for U.S. tax purposes and $190.8 million of post 2017 NOLs for U.S. tax purposes. Our pre-2018 NOLs will expire in varying amounts from 2022 through 2037, if not utilized; and can offset 100% of future taxable income for regular tax purposes. Any NOLs arising in 2018, 2019 and 2020 can generally be carried back five years, carried forward indefinitely and can offset 100% of future taxable income for tax years before January 1, 2021 and up to 80% of future taxable income for tax years after December 31, 2020. Any NOLs arising on or after January 1, 2021, cannot be carried back and can generally be carried forward indefinitely and can offset up to 80% of future taxable income for regular tax purposes, (the alternative minimum tax no longer applies to corporations after January 1, 2018).

The use of our NOLs will be limited if there is an "ownership change" in our common stock, generally a cumulative ownership change exceeding 50% during a three year period, as determined under Section 382 of the Internal Revenue Code. As of December 31, 2021, we have not had an ownership change as defined by Section 382. Given historical losses, uncertainties exist as to the future utilization of the NOL carryforwards, therefore, the Company has established a valuation allowance of $117.27 million at December 31, 2020 and $124.08 million at December 31, 2021.

The reconciliation of income tax computed at the U.S. federal statutory tax rates to income tax expense is:

	Years Ended December 31,	
	2020	2021
	(in thousands)	
Tax benefit at U.S. Statutory rates	$ 38,749	$ 9,359
Change in deferred tax asset valuation allowance	(37,193)	(7,007)
Alternative minimum tax expense	-	-
Adjustment to deferred tax assets	-	(3,421)
Permanent differences	(276)	368
Return to provision estimated revision	(3,069)	-
State income taxes, net of federal effect	1,789	688
Other	-	13
	$ -	$ -

As of December 31, 2020 and 2021, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2014 through 2021 remain open to examination by the tax jurisdictions to which the Company is subject.

New tax legislation, commonly referred to as the Tax Cuts and Jobs Act (H.R. 1), was enacted on December 22, 2017. Since our federal deferred tax asset was fully offset by a valuation allowance, the reduction in the U.S. corporate income tax rate to 21% did not materially affect the Company's financial statements. Significant provisions that may impact income taxes in future years include: the repeal of the corporate Alternative Minimum Tax, the limitation on the current deductibility of net interest expense in excess of 30% of adjusted taxable income for levered balance sheets, (for tax years 2019 & 2020, the CARES Act temporarily adjusted the limitation in excess of 50% of adjusted taxable income for levered balance sheets at the taxpayer's discretionary election), a limitation on utilization of net operating losses generated after tax year 2017 to 80% of taxable income, the unlimited carryforward of net operating losses generated after tax year 2017, temporary 100% expensing of certain business assets, additional limitations on certain general and administrative expenses, and changes in determining the excessive compensation limitation. Currently, we do not anticipate paying cash federal income taxes in the near term due to any of the legislative changes, primarily due to the availability of our net operating loss carryforwards. Future interpretations relating to the recently enacted U.S. federal income tax legislation which vary from our current interpretation and possible changes to state tax laws in response to the recently enacted federal legislation may have a significant effect on this projection.

Note 8 - Commitments and Contingencies	12 Months Ended Dec. 31, 2021
Notes to Financial Statements	
Commitments and Contingencies Disclosure [Text Block]	**8. Commitments and Contingencies** *Litigation and Contingencies* From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At December 31, 2021, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on the Company.

Note 9 - Earnings Per Share

12 Months Ended Dec. 31, 2021

Notes to Financial Statements

Earnings Per Share [Text Block]

9. Earnings per Share

The following table sets forth the computation of basic and diluted earnings per share:

	Years Ended December 31,	
	2020	**2021**
Numerator:		
Net loss	$ (184,522)	$ (44,567)
Denominator for basic earnings per share - weighted-average common shares outstanding	8,382	8,408
Effect of dilutive securities: Stock options, restricted shares and performance based shares	-	-
Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares	8,382	8,408
Net loss per common share - basic	$ (22.01)	$ (5.30)
Net loss per common share - diluted	$ (22.01)	$ (5.30)

Basic earnings per share, excluding any dilutive effects of stock options and unvested restricted stock, is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted income (loss) per share is computed similar to basic; however diluted income (loss) per share reflects the assumed conversion of all potentially dilutive securities.

Note 10 - Benefit Plans	12 Months Ended Dec. 31, 2021
Notes to Financial Statements	
Compensation and Employee Benefit Plans [Text Block]	**10. Benefit Plans** The Company has a defined contribution plan (401(k) plan) covering all eligible employees. For 2020, in accordance with the safe harbor provisions of the Plan, the Company contributed $142,820. The Company contributed $123,639 to the plan for 2021, and will contribute an additional $1,637 in 2022 for 2021. The Company adopted the safe harbor provisions which requires it to contribute a fixed match to each participating employee's contribution to the plan. The fixed match is set at the rate of dollar for dollar on the first 1% of eligible pay contributed, then 50 cents on the dollar for each additional percentage point of eligible pay contributed, up to 5%. Each employee's eligible pay with respect to calculating the fixed match is limited by IRS regulations. In addition, the Board of Directors, at its sole discretion, may authorize the Company to make additional contributions to each participating employee. The employee contribution limit for 2020 and 2021 was $19,500 for employees under the age of 50 and $26,000 for employees 50 years of age or older.

Note 11 - Hedging Program and Derivatives	12 Months Ended
	Dec. 31, 2021

Notes to Financial Statements

Derivative Instruments and Hedging Activities Disclosure [Text Block]

11. Hedging Program and Derivatives

As of December 31, 2021 the Company is not party to any hedge agreements. The liability as of December 31, 2021 relates to the December 2021 contract settlement.

The following table illustrates the impact of derivative contracts on the Company's balance sheet:

Fair Value Derivative Contracts as of December 31, 2020

Derivatives not designated as hedging instruments	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives - current	$ 9,639	Derivatives - current	$ 480
Commodity price derivatives	Derivatives - long-term	10,281	Derivatives - long-term	-
		$ 19,920		$ 480

Fair Value Derivative Contracts as of December 31, 2021

Derivatives not designated as hedging instruments	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives - current	$ -	Derivatives - current	$ 442
		$ -		$ 442

Gains and losses from derivative activities are reflected as "Loss (gain) on derivative contracts" in the accompanying Consolidated Statements of Operations. The net estimated value of our commodity derivative contracts was a liability of approximately $0.4 million as of December 31, 2021. For the year-ended December 31, 2021, we recognized a loss of $33.0 million related to our derivative contracts, including a loss or $7.1 million related to cancelled contracts. For the year ended December 31, 2020, we recognized a gain on our derivative contracts of approximately $42.9 million.

Note 12 - Financial Instruments	12 Months Ended
	Dec. 31, 2021

Notes to Financial Statements

Fair Value Disclosures [Text Block]

12. Financial Instruments

There is a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.
- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2020 and 2021, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2020
Assets:				
NYMEX fixed price derivative contracts	$ -	$ 19,920	$ -	$ 19,920
Total Assets	$ -	$ 19,920	$ -	$ 19,920
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 480	$ -	$ 480
Total Liabilities	$ -	$ 480	$ -	$ 480

	Quoted Prices in Active Markets for Identical	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2021

	Assets (Level 1)			
Assets:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$ -
Total Assets	$ -	$ -	$ -	$ -
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 442	$ -	$ 442
Total Liabilities	$ -	$ 442	$ -	$ 442

The Company's derivative contracts during the years ended December 31, 2021 and December 31, 2020 consisted of NYMEX-based fixed price commodity swaps and basis differential swaps. The NYMEX-based fixed price derivative contracts were indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2.

Nonrecurring Fair Value Measurements

Non-financial assets and liabilities measured at fair value on a nonrecurring basis included certain non-financial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used. The assessment considers the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, the economic viability of development if proved reserves were assigned and other current market conditions. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligation is presented in Note 1.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable and accounts payable approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

Note 13 - Lease Accounting Standard

Notes to Financial Statements

Lessee, Operating Leases [Text Block]

	12 Months Ended Dec. 31, 2021

13. Lease Accounting Standard

Nature of Leases

We lease certain real estate, field equipment and other equipment under cancelable and non-cancelable leases to support our operations. A more detailed description of our significant lease types is included below.

Real Estate Leases

We rented a residence in North Dakota from a third party for living accommodations for certain field employees. Our real estate lease was non-cancelable with a term of five years, through August 31, 2024. We have concluded our real estate agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. Upon completion of the primary term, both parties have substantive rights to terminate the lease. As a result, enforceable rights and obligations do not exist under the rental agreements subsequent to the primary term. The North Dakota residential lease was assigned to a third-party on January 3, 2022. See Note 14 "Subsequent Events."

Field Equipment

We rent compressors and coolers from third parties in order to facilitate the downstream movement of our production from our drilling operations to market. Our compressor and cooler arrangements are typically structured with a non-cancelable primary term of one year and continue thereafter on a month-to-month basis subject to termination by either party with thirty days' notice. These leases are considered short term and are not capitalized. We have a small number of compressor leases that are longer than twelve months. We have concluded that our compressor and cooler rental agreements represent operating leases with a lease term that equals the primary non-cancelable contract term. Upon completion of the primary term, both parties have substantive rights to terminate the lease. As a result, enforceable rights and obligations do not exist under the rental agreement subsequent to the primary term. We enter into daywork contracts for drilling rigs with third parties to support our drilling activities. Our drilling rig arrangements are typically structured with a term that is in effect until drilling operations are completed on a contractually specified well or well pad. Upon mutual agreement with the contractor, we typically have the option to extend the contract term for additional wells or well pads by providing thirty days' notice prior to the end of the original contract term. We have concluded that our drilling rig arrangements represent short-term operating leases. The accounting guidance requires us to make an assessment at contract commencement if we are reasonably certain that we will exercise the option to extend the term. Due to the continuously evolving nature of our drilling schedules and the potential volatility in commodity prices in an annual period, our strategy to enter into shorter term drilling rig arrangements allows us the flexibility to respond to changes in our operating and economic environment. We exercise our discretion in choosing to extend or not extend contracts on a rig by rig basis depending on the conditions present at the time the contract expires. At the time of contract commencement, we have determined we cannot conclude with reasonable certainty if we will choose to extend the contract beyond its original term. Pursuant to the full cost method, these costs are capitalized as part of natural gas and oil properties on our balance sheet when paid.

Discount Rate

Our leases typically do not provide an implicit rate. Accordingly, we are required to use our incremental borrowing rate in determining the present value of lease payments based on the information available at commencement date. Our incremental borrowing rate reflects the estimated rate of interest that we would pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. We use the implicit rate in the limited circumstances in which that rate is readily determinable.

Practical Expedients and Accounting Policy Elections

Certain of our lease agreements include lease and non-lease components. For all existing asset classes with multiple component types, we have utilized the practical expedient that exempts us from separating lease components from non-lease components. Accordingly, we account for the lease and non-lease components in an arrangement as a single lease component. In addition, for all of our existing asset classes, we have made an accounting policy election not to apply the lease recognition requirements to our short-term leases (that is, a lease that, at commencement, has a lease term of 12 months or less and does not include an option to purchase the underlying asset that we are reasonably certain to exercise). Accordingly, we recognize lease payments related to our short-term leases in our statement of operations on a straight-line basis over the lease term which has not changed from our prior recognition. To the extent that there are variable lease payments, we recognize those payments in our statement of operations in the period in which the obligation for those payments is incurred. None of our current leases contain variable payments. Refer to “Nature of Leases” above for further information regarding those asset classes that include material short-term leases.

The components of our total lease expense for the years ended December 31, 2020 and December 31, 2021, the majority of which is included in lease operating expense, are as follows:

	For the Year Ended December 31,	
	2020	**2021**
	(in thousands)	
Operating lease cost	$ 114	$ 65
Short-term lease expense (1)	2,183	1,913
Total lease expense	$ 2,297	$ 1,978
Short-term lease costs (2)	$ 973	$ -

(1) Short-term lease expense represents expense related to leases with a contract term of 12 months or less.

(2) These short-term lease costs are related to leases with a contract term of 12 months or less which are related to drilling rigs and are capitalized as part of natural gas and oil properties on our balance sheet.

Supplemental balance sheet information related to our operating leases is included in the table below:

	For the Year Ended December 31,	
	2020	**2021**
	(in thousands)	
Operating lease Right of Use asset	$ 228	$ 173
Operating lease liability - current	$ 53	$ 40
Operating lease liabilities - long-term	$ 150	$ 110

Our weighted average remaining lease term and weighted average discount rate for our operating leases are as follows:

For the Year Ended December 31,	
2020	**2021**
(in thousands)	

Weighted Average Remaining Lease Term (in years)	10.68	12.46
Weighted Average Discount Rate	6%	6%

Our lease liabilities with enforceable contract terms that are greater than one year mature as follows:

	Operating Leases
	(in thousands)
2022	40
2023	41
2024	28
2025	4
2026	4
Thereafter	94
Total lease payments	211
Less imputed interest	(61)
Total lease liability	$ 150

Supplemental cash flow information related to our operating leases is included in the table below:

	For the Year Ended December 31,	
	2020	**2021**
	(in thousands)	
Cash paid for amounts included in the measurement of lease liabilities	$ 114	$ 65
Right of Use assets added in exchange for lease obligations (since adoption)	$ 125	$ -

Note 14 - Subsequent Events

12 Months Ended Dec. 31, 2021

Notes to Financial Statements

Subsequent Events [Text Block]

14. Subsequent Events

Restructuring

Pursuant to the Exchange Agreement, dated as of January 3, 2022, between Abraxas and AG Energy Funding, LLC ("AGEF") and certain other agreements entered into by Abraxas on January 3, 2022, we effectuated a restructuring of our then-existing indebtedness through a multi-part interdependent de levering transaction consisting of: (i) an Asset Purchase and Sale Agreement pursuant to which Abraxas sold to Lime Rock Resources V-A, L.P. certain oil, gas, and mineral properties in the Williston Basin region of North Dakota and other related assets belonging to the Company and its subsidiaries for $87,200,000 in cash ($73.3 million after customary closing adjustments) (the "Sale"), (ii) the pay down of the indebtedness and other obligations of Abraxas and its subsidiaries under the First Lien Credit Facility, by and among Abraxas, the financial institutions party thereto as lenders, and Société Générale, as "Issuing Lender" and administrative agent and certain specified secured hedges from the proceeds of the Sale and, to the extent necessary, other cash of Abraxas; and (iii), a debt for equity exchange of the indebtedness and other obligations of Abraxas and its subsidiaries under the Second Lien Credit Facility, by and among Abraxas, the financial institutions party thereto as lenders, and Angelo Gordon Energy Servicer, LLC, as administrative agent and all related loan and security documents (the "Exchange" and, together with the transactions referred to in clauses (i) and (ii), the "Restructuring").

AGEF was issued 685,505 shares of Series A Preferred Stock of the Company in the Exchange. The Series A Preferred Stock has the terms set forth in the Company's filed Preferred Stock Certificate of Designation (the "Certificate). Pursuant to the Certificate, any proceeds distributed to the Company's stockholders or otherwise received in respect of the capital stock of the Company in a merger or other liquidity event will be allocated among the Series A Preferred Stock and the Company's common stock as follows: (1) first, 100% to the Series A Preferred Stock until the Series A Preferred Stock has received $100 million of proceeds in the aggregate (the "Tier One Preference Amount"), (2) second, 95% to the Series A Preferred Stock and 5% to the Company's common stock until the Series A Preferred Stock has received $137.1 million, plus a 6.0% annual rate of return thereon from the date hereof; (3) thereafter, 75% to the Series A Preferred Stock and 25% to the Company's common stock. The Exchange Agreement entered into in connection with the Restructuring also provides for the potential funding by AGEF of an additional amount up to $12.0 million, if agreed to by AGEF and the disinterested members of the Company's Board of Directors. Any such additional amount funded would result in an increase to the Tier One Preference Amount equal to 1.5 x the amount of such additional funding. The shares of Series A Preferred Stock vote together as a single class with the Company's common stock, and each share of Series A Preferred Stock entitles the holder thereof to 69 votes. Accordingly, AGEF's ownership of the Series A Preferred Stock entitle it to approximately 85% of the voting power of the Company's current outstanding capital stock.

Todd Dittmann, Damon Putman and Daniel Baddeloo, each of whom are employees of AGEF, were appointed to Abraxas' Board of Directors.

Change In Majority of Board of Directors

Todd Dittmann, Damon Putman and Daniel Baddeloo, each of whom are employees of AGEF were appointed as members of the Board of Directors in January 2022.

Note 15 - Events of Default

12 Months Ended Dec. 31, 2021

Notes to Financial Statements

Substantial Doubt about Going Concern [Text Block]

15. Events of Default

In connection with the completion of our financial statements for the year ended December 31, 2020, the Company tested its financial ratios for the fiscal quarter ended December 31, 2020 and determined that it was not in compliance the first lien debt to consolidated EBITDAX ratio covenant under the First Lien Credit Facility. Our failure to comply with such covenant contributed to our independent accountant's including an explanatory paragraph with regard to the Company's ability to continue as a "going concern" in issuing their opinion on our financial statements for the year ended December 31, 2020. The "going concern" opinion resulted in an additional event of default under the First Lien Credit Facility and the Second Lien Credit Facility. Additional events of default occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended. However, in connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

First Lien Credit Facility

Events of default have occurred under the First Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its inability to comply with the first lien debt to consolidated EBITDAX ratio for the fiscal quarter ended December 31, 2020, (iii) our failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the First Lien Credit Facility, and (iv) certain cross-defaults that occurred, or may occur, as a result of the events of default under the First Lien Credit Agreement and corresponding cross-defaults under the Second Lien Credit Facility and cross-defaults or similar termination events under our hedging contracts. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 "Subsequent Events."

Second Lien Credit Facility

Events of default occurred under the Second Lien Credit Facility as a result of (i) the Company's failure to timely deliver audited financial statements without a "going concern" or like qualification for the fiscal year ended December 31, 2020, (ii) its failure to cause certain deposit accounts to be subject to control agreements in favor of the administrative agent for the Second Lien Credit Facility, (iii) the failure of the Company to meet certain hedging requirements, (iv) the Company's inability to comply with the total leverage ratio for the fiscal quarter ended September 30, 2021, (v) the Company's inability to comply with minimum asset coverage ratio for the fiscal quarter ended September 30, 2021, and (vi) certain cross-defaults that occurred, or may could have occurred, as a result of the occurrence of events of default under the First Lien Credit Facility and corresponding cross-defaults or similar termination events under our hedging contracts. Additional events of default occurred as of September 30, 2021, as a result of our failure to comply with certain financial covenants under the Second Lien Credit Facility, as amended.

On April 16, 2021, we received a Notice of Default and Reservation of Rights (the "Notice of Default") from Angelo Gordon stating that we have defaulted under the Second Lien Credit Facility, and that, as a result, the lenders have accelerated our obligations due thereunder and have reserved their rights to pursue additional remedies in the future.

The Notice of Default declared that our obligations under the Second Lien Credit Facility were immediately due and payable, in each case without presentment, demand, protest or other requirements of any kind, and we began to bear interest at the rate applicable to such amount under the Second Lien Credit Facility, plus an additional 3%. Additionally, the administrative agent and the lenders reserved their right to exercise further rights, powers and remedies under the Second Lien Credit Facility, at any time or from time to time, with respect to any of the events of default described above. In connection with the restructuring that was completed on January 3, 2022, our First Lien Credit Facility was retired and our Second Lien Credit Facility was converted to Series A Preferred Stock. See Note 14 “Subsequent Events.”

Hedging Contracts

Effective April 12, 2021, Morgan Stanley Capital Group, Inc. (“Morgan Stanley”), a hedge counterparty to several of our hedging contracts sent us notice of events of default and early termination with respect to the hedging contracts to which they are a counterparty. The notice indicated Morgan Stanley’s election to exercise termination rights under the hedge contract, which Morgan Stanley asserted arose as a result of the occurrence of events of default under the First Lien Credit Facility, of which Morgan Stanley is a lender, holding approximately 3.7% of the outstanding obligations under the First Lien Credit Facility. The termination value of the hedging agreements with Morgan Stanley as of the effective date of the notice was approximately $9.2 million. We subsequently voluntarily terminated most of our other hedging arrangements. As a result of the settlement of the terminated hedges, we had outstanding obligations of $9.2 million, including the $8.4 million to Morgan Stanley. These obligations were added to the outstanding balance of the First Lien Credit Facility and accrued interest at the default rate until repaid. Our other hedging agreements were also terminated. As of December 31, 2021, we no longer had any hedging agreements in place.

Note 16 - Supplemental Oil and Gas Disclosures (Unaudited)	12 Months Ended
	Dec. 31, 2021
Notes to Financial Statements	
Oil and Gas Exploration and Production Industries Disclosures [Text Block]	

16. Supplemental Oil and Gas Disclosures (Unaudited)

The accompanying tables present information concerning the Company's oil and gas producing activities "Disclosures about Oil and Gas Producing Activities." Capitalized costs relating to oil and gas producing activities are as follows as of December 31, 2020 and 2021:

	Years Ended December 31, (in thousands)	
	2020	2021
Proved oil and gas properties	$ 1,167,333	$ 1,165,707
Unproved properties	-	-
Total	1,167,333	1,165,707
Accumulated depreciation, depletion, amortization and impairment	(1,060,649)	(1,074,144)
Net capitalized costs	$ 106,684	$ 91,563

Cost incurred in oil and gas property acquisition and development activities were as follows for the years ended December 31, 2020 and 2021 (in thousands):

	2020	2021
Development costs	$ 5,238	$ 1,145
Exploration costs	-	-
Property acquisition costs	-	-
	$ 5,238	$ 1,145

Results of operations from oil and gas producing activities were as follows for the years ended December 31, 2020 and 2021:

	2020	2021
Revenues	$ 42,984	$ 78,836
Production costs	(21,090)	(24,137)
Depreciation, depletion and amortization	(22,679)	(13,495)
Accretion of future site restoration	(414)	(330)
Proved property impairment	(186,980)	-
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$(188,179)	$ 40,874
Depletion rate per barrel of oil equivalent	$ 12.58	$ 6.67

Estimated Quantities of Proved Oil and Gas Reserves

Reserve estimates are inherently imprecise and estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, the estimates are expected to change as future information becomes available. The estimates have been predominately prepared by independent petroleum reserve engineers. Proved oil and gas reserves are the estimated quantities of oil and 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. Proved developed oil and gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. All of the Company's proved reserves are located in the continental United States.

Proved reserves were estimated in accordance with guidelines established by the SEC and the FASB, which require that reserve estimates be prepared under existing economic and operating conditions with no provision for price and cost escalations except by contractual arrangements; therefore, the unweighted average prior 12-month first-day-of-the-month commodity prices and year-end costs were used in estimating reserve volumes and future net cash flows for the periods presented.

The following table presents the Company's estimate of its net proved developed and undeveloped oil and gas reserves as of December 31, 2020 and 2021:

	Total			
	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Oil Equivalents (Mboe)
Proved Developed Reserves:				
December 31, 2020	9,538	3,187	24,318	16,778
December 31, 2021	6,883	2,914	30,158	14,823
Proved Undeveloped Reserves:				
December 31, 2020	-	-	-	-
December 31, 2021	-	-	-	-

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company's proved oil and gas reserves have been estimated by the independent petroleum engineering firm, DeGolyer & MacNaughton, assisted by the engineering and operations departments of the Company as of December 31, 2020 and December 31, 2021. The following information has been prepared in accordance with SEC rules and accounting standards based on the 12-month first-day-of-the-month unweighted average prices in accordance with provisions of the FASB's Accounting Standards Update No. 2010-03, "Extractive Activities—Oil and Gas (Topic 932)." Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future net cash flows have not been adjusted for commodity derivative contracts outstanding at the end of each year. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the tax basis and net operating losses associated with the properties. Since prices used in the calculation are average prices for 2020, and 2021, the standardized measure could vary significantly from year to year based on the market conditions that occurred during a given year.

The technical personnel responsible for preparing the reserve estimates at DeGolyer & MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer & MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in our properties and are not employed on a contingent fee basis. All reports by DeGolyer & MacNaughton were developed utilizing studies performed by DeGolyer & MacNaughton and assisted by the Engineering and Operations departments of Abraxas. Reserves are estimated by independent petroleum engineers. The report of DeGolyer & MacNaughton dated February 4, 2022, contains further discussions of the reserve estimates and evaluations prepared by DeGolyer & MacNaughton as well as the qualifications of DeGolyer & MacNaughton's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of proved reserves at December 31, 2020 and 2021 were based on studies performed by our independent petroleum engineers assisted by the Engineering and Operations departments of Abraxas. The Engineering department is directly responsible for Abraxas' reserve evaluation process. The Vice President of Engineering is the manager of this department and is the primary technical person responsible for this process. The Vice President of Engineering holds a Bachelor of Science degree in Petroleum Engineering and has 42 years of experience in reserve evaluations. The Vice President of Engineering is a Registered Professional Engineer in the State of Texas. The operations department of Abraxas assisted in the process.

The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted to represent the fair market value of the Company's proved oil and gas reserves. An estimate of fair market value would also take into account, among other factors, the recovery of reserves not classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the Standardized Measure. The table below sets forth the Standardized Measure of our proved oil and gas reserves for the years ended December 31, 2020 and 2021 :

	Years Ended December 31, (in thousands)	
	2020	**2021**
Future cash inflows	$ 345,869	$ 485,982
Future production costs	(166,781)	(222,309)
Future development costs	(6,291)	(5,623)
Future income tax expense	-	-
Future net cash flows	172,797	258,050
Discount	$ (66,113)	$(104,775)
Standardized Measure of discounted future net cash relating to proved reserves	$ 106,684	$ 153,275

Significant Accounting Policies (Policies)	12 Months Ended Dec. 31, 2021
Accounting Policies [Abstract]	
Consolidation, Policy [Policy Text Block]	*Nature of Operations* We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States. Our oil and gas assets are located primarily in two operating regions in the United States: the Rocky Mountains and Permian/Delaware Basin. The terms "Abraxas," "Abraxas Petroleum," "we," "us," "our" or the "Company" refer to Abraxas Petroleum Corporation and all of its subsidiaries, including Raven Drilling LLC ("Raven Drilling").
Rig Accounting [Policy Text Block]	*Rig Accounting* In accordance with SEC Regulation S-X, no income is recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates holds an ownership, or other economic interest. Any income not recognized as a result of this limitation is credited to the full cost pool and recognized through lower amortization as reserves are produced. During 2020 and 2021 the drilling rig was idle, accordingly the cost of the rig was charged to the statement of operations.
Use of Estimates, Policy [Policy Text Block]	*Use of Estimates* The consolidated financial statements of the Company have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. The most significant estimates pertain to proved oil, gas and NGL reserves and related cash flow estimates used in impairment tests of oil and gas properties, the fair value of assets and liabilities acquired in business combinations, derivative contracts, the provision for income taxes including uncertain tax positions, stock based compensation, asset retirement obligations, accrued oil and gas revenues and expenses, as well as estimates of expenses related to depreciation, depletion, amortization and accretion. Actual results could differ from those estimates. The process of estimating oil and gas reserves in accordance with SEC requirements is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, differentials, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, our ability to fund estimated development cost, prevailing oil and gas prices and other factors, many of which are beyond our control.
Reclassification, Comparability Adjustment [Policy Text Block]	*Reclassifications* Certain reclassifications have been made to the prior year financial statements to conform to the current period presentation. These reclassifications were to share and per share data related to the 1 for 20 reverse stock split effective October 19, 2020 and had no effect on our previously reported results of operations.

Concentration Risk, Credit Risk, Policy [Policy Text Block]

Concentration of Credit Risk

Financial instruments which potentially expose the Company to credit risk consist principally of trade receivables and derivative contracts. Accounts receivable are generally from companies with significant oil and gas marketing or operating activities. The Company performs ongoing credit evaluations and, generally, requires no collateral from its customers. The counterparties to our derivative contracts are the same financial institutions from which we have outstanding debt; accordingly, we believe our exposure to credit risk to these counterparties is currently mitigated in part by this, as well as the current overall financial condition of the counterparties.

The Company maintains any cash and cash equivalents in excess of federally insured limits in prominent financial institutions considered by the Company to be of high credit quality.

Cash and Cash Equivalents, Policy [Policy Text Block]

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits and short-term investments with original maturities of three months or less.

Accounts Receivable [Policy Text Block]

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of approximately $0.1 million at December 31, 2020 and 2021 . The allowance for doubtful accounts is determined based on the Company's historical losses, as well as a review of certain accounts. Accounts are charged off when collection efforts have failed and the account is deemed uncollectible.

Segment Reporting, Policy [Policy Text Block]

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of oil and gas with all of the Company's operational activities being conducted in the U.S. The Company's current operational activities and the Company's consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long lived assets located outside the U.S.

Full Cost Method Using Gross Revenue Method, Policy [Policy Text Block]

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, certain direct costs and indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited by country, to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. Costs in excess of the present value of estimated future net revenues are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties for full cost accounting companies with proceeds accounted for as an adjustment of capitalized cost. An exception to this rule occurs when the adjustment to the full cost pool results in a significant alteration of the relationship between capitalized cost and proved reserves. The Company applies the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. The impairment calculations do not consider the impact of our commodity derivative positions as generally accepted accounting principles only allow the inclusion of derivatives designated as cash flow hedges. As of December 31, 2020, our capitalized cost of oil and gas properties exceeded the future net revenue from our estimated proved reserves resulting in the recognition of an impairment of $187.0 million. As of December 31, 2021, our capitalized cost of oil and gas properties did not exceed the future net revenue from our estimated proved reserves.

Property, Plant and Equipment, Policy [Policy Text Block]

Other Property and Equipment

Other property and equipment are recorded at cost. Depreciation of other property and equipment is provided over the estimated useful lives using the straight-line method. Major renewals and improvements are recorded as additions to the property and equipment accounts. Repairs that do not improve or extend the useful lives of assets are expensed.

Estimate of Proved Oil and Gas Reserves Policy [Policy Text Block]

Estimates of Proved Oil and Gas Reserves

Estimates of our proved reserves included in this report are prepared in accordance with GAAP and SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Our proved reserve information included in this report was based on studies performed by our independent petroleum engineers assisted by the engineering and operations departments of Abraxas. Estimates prepared by other third parties may be higher or lower than those included herein. Because these estimates depend on many assumptions, all of which may substantially differ from future actual results, reserve estimates will be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may cause material revisions to the estimate.

In accordance with SEC requirements, we based the estimated discounted future net cash flows from proved reserves on the average of oil and gas prices based on the unweighted average 12 month first-day-of-month pricing. Future prices and costs may be materially higher or lower than these prices and costs which would impact the estimated value of our reserves.

The estimates of proved reserves materially impact depreciation, depletion and amortization, or DD&A expense. If the estimates of proved reserves decline, the rate at which we record DD&A expense will increase, reducing future net income. Such a decline may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields.

Derivatives, Policy [Policy Text Block]

Derivative Instruments and Hedging Activities

The Company enters into agreements to hedge the risk of future oil and gas price fluctuations. Such agreements are typically in the form of fixed price commodity and basis swaps, which limit the impact of price fluctuations with respect to the Company's sale of oil and gas. While it is never management's intention to hold or issue derivative instruments for speculative trading purposes, conditions could arise where actual production is less than estimated which could result in over hedged volumes.

All derivative instruments are recorded on the Consolidated Balance Sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The derivative instruments the Company utilizes are based on index prices that may and often do differ from the actual oil and gas prices realized in its operations. These variations often result in a lack of adequate correlation to enable these derivative instruments to qualify for hedge accounting rules as prescribed by Accounting Standards Codification ("ASC") 815. Accordingly, the Company does not account for its derivative instruments as cash flow hedges for financial reporting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings and included in net gains (losses) on commodity derivative contracts in the Consolidated Statements of Operations.

Fair Value of Financial Instruments, Policy [Policy Text Block]

Fair Value of Financial Instruments

The Company includes fair value information in the notes to consolidated financial statements when the fair value of its financial instruments is materially different from the carrying value. The carrying value of those financial instruments that are classified as current, except for derivative instruments, approximates fair value because of the short maturity of these instruments. For noncurrent financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments.

Share-based Payment Arrangement [Policy Text Block]

Share-Based Payments

Options granted are valued at the date of grant and expense is recognized over the vesting period. The Company currently utilizes a standard option pricing model (Black-Scholes) to measure the fair value of stock options granted to employees and directors. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such restricted stock is determined using the market price on the grant date and expense is recorded over the vesting period. For the years ended December 31, 2020 and 2021, stock-based compensation was approximately $1.3 million and $0.9 million, respectively.

Asset Retirement Obligation and Environmental Cost [Policy Text Block]

Restoration, Removal and Environmental Liabilities

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum substances at various sites. Environmental expenditures are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed.

Liabilities for expenditures of a noncapital nature are recorded when environmental assessments and/or remediation is probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments for the liability or component are fixed or reliably determinable.

The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and we amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements. Each year, the Company reviews, and to the extent necessary, revises its asset retirement obligation estimates.

The following table (in thousands) summarizes changes in the Company's future site restoration obligations during the two years ended December 31:

	2020	2021
Beginning future site restoration obligation	$ 7,420	$ 7,360
New wells placed on production and other	43	1
Deletions related to property disposals	(216)	(2,845)
Deletions related to plugging costs	(235)	(342)
Accretion expense and other	414	330
Revisions and other	(66)	204
Ending future site restoration obligation	$ 7,360	$ 4,708

Revenue [Policy Text Block]

Revenue Recognition and Major Purchasers

The Company recognizes oil and gas revenue from its interest in producing wells as oil and gas is sold from those wells, net of royalties, control of the product has transferred to the purchaser and collectability is reasonably assured.

During 2020 four purchasers accounted for 73% of oil and gas revenues. During 2021, four purchasers accounted for 83% of oil and gas revenues.

Deferred Charges, Policy [Policy Text Block]

Deferred Financing Fees

Deferred financing fees are being amortized on the effective yield basis over the term of the related debt.

Income Tax, Policy [Policy Text Block]

Income Taxes

Deferred tax assets and liabilities are recognized for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to be in effect with respect to taxable income in the years in which those temporary differences are expected to be recovered or settled. Uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, we have established a valuation allowance of $124.08 million for deferred tax assets at December 31, 2021.

Income Tax Uncertainties, Policy [Policy Text Block]

Accounting for Uncertainty in Income Taxes

Evaluation of a tax position is a two-step process. The first step is to determine whether it is more-likely-than-not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation based on the technical merits of that position. The second step is to measure a tax position that meets the more-likely-than-not threshold to determine the amount of benefit to be recognized in the financial statements. A tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement.

Tax positions that previously failed to meet the more-likely-than-not recognition threshold should be recognized in the first subsequent period in which the threshold is met. Previously recognized tax positions that no longer meet the more-likely-than-not criteria should be de-recognized in the first subsequent reporting period in which the threshold is no longer met. Penalties and interest are classified as income tax expense. The Company had no uncertain income tax positions as of December 31, 2021.

New Accounting Pronouncements, Policy [Policy Text Block]

Adoption of New Accounting Standards

In March 2020, the FASB issued ASU No. 2020-04, "Reference Rate Reform (Topic 840): Facilitation of the Effects of Reference Rate Reform on Financial Reporting" ("ASU 2020-04"), which provides companies with optional guidance to ease the potential accounting burden associated with transitioning away from reference rates (e.g., London Interbank Offered Rate ("LIBOR")) that are expected to be discontinued. ASU 2020-04 allows, among other things, certain contract modifications, such as those within the scope of Topic 470 on debt, to be accounted as a continuation of the existing contract. This ASU was effective upon the issuance and its optional relief can be applied through December 31, 2022. The Company will consider this optional guidance prospectively, if applicable.

In May 2020, the SEC adopted final rules that amend the financial statement requirements for significant business acquisitions and dispositions. Among other changes, the final rules modify the significance tests and improve the disclosure requirements for acquired or to be acquired businesses and related pro forma financial information, the periods those financial statements must cover, and the form and content of the pro forma financial information. The final rules do not modify requirements for the acquisition and disposition of significant amounts of assets that do not constitute a business. The final rules are effective January 1, 2021, but earlier compliance is permitted. The Company will consider these final rules and update its disclosures, as applicable.

Note 1 - Organization and Significant Accounting Policies (Tables)

12 Months Ended Dec. 31, 2021

Notes Tables

Schedule of Change in Asset Retirement Obligation [Table Text Block]

	2020	2021
Beginning future site restoration obligation	$7,420	$ 7,360
New wells placed on production and other	43	1
Deletions related to property disposals	(216)	(2,845)
Deletions related to plugging costs	(235)	(342)
Accretion expense and other	414	330
Revisions and other	(66)	204
Ending future site restoration obligation	$7,360	$ 4,708

Note 2 - Revenue From Contracts With Customers (Tables)

12 Months Ended Dec. 31, 2021

Notes Tables

Disaggregation of Revenue [Table Text Block]

	Years Ended December 31,					
	2020			2021		
	Oil	Gas	NGL	Oil	Gas	NGL
Operating Region						
Permian/ Delaware Basin	$ 22,891	$ 335	$ 163	$ 32,666	$ 4,474	$ 2,181
Rocky Mountain (1)	$ 19,078	$ 251	$ 266	$ 28,562	$ 4,182	$ 6,771

Note 4 - Long-term Debt (Tables)	12 Months Ended Dec. 31, 2021
Notes Tables	
Schedule of Long-term Debt Instruments [Table Text Block]	(see table below)
Contractual Obligation, Fiscal Year Maturity [Table Text Block]	(see table below)

Schedule of Long-term Debt Instruments [Table Text Block]

	Years Ended December 31, 2020	Years Ended December 31, 2021
	(In thousands)	
First Lien Credit Facility	$ 95,000	$ 71,400
Second Lien Credit Facility	112,695	134,907
Exit fee - Second Lien Credit Facility	10,000	10,000
Real estate lien note	2,810	2,515
	220,505	218,822
Less current maturities	(202,751)	(212,688)
	17,754	6,134
Deferred financing fees and debt issuance cost - net	(15,239)	(3,929)
Total long-term debt, net of deferred financing fees and debt issuance costs	$ 2,515	$ 2,205

Contractual Obligation, Fiscal Year Maturity [Table Text Block]

Years ending December 31, (In thousands)	
2022	$216,617
2023	2,205
2024	
2025	-
2026	-
Thereafter	-
Total	$218,822

Note 5 - Property and Equipment (Tables)

12 Months Ended Dec. 31, 2021

Notes Tables

Property, Plant and Equipment [Table Text Block]

	Estimated Useful life Years	December 31, 2020	December 31, 2021
		(In thousands)	
Oil and gas properties (1)	-	$ 1,167,333	$ 1,165,707
Equipment and other	3-39	15,348	15,257
Drilling rig	15	24,108	24,080
		1,206,789	1,205,044
Accumulated depreciation, depletion, amortization and impairment		(1,083,843)	(1,099,075)
Net Property and Equipment		$ 122,946	$ 105,969

Note 6 - Stock-based Compensation and Option Plans (Tables)	12 Months Ended Dec. 31, 2021
Notes Tables	
Share-based Payment Arrangement, Option, Activity [Table Text Block]	(table below)

	Options (000s)	Weighted average exercise price	Weighted average remaining life	Intrinsic value per share
Options outstanding December 31, 2019	297	$ 49.41		
Forfeited/Expired	(101)	48.96		
Options outstanding December 31, 2020	196	$ 49.69		
Forfeited/Expired	(141)	48.11		
Options outstanding December 31, 2021	55	53.79	3.3	$ 0.00
Exercisable at end of year	55	53.79	3.3	$ 0.00

	2020	2021
Weighted average grant date fair value of stock options granted (per share)	$ -	$ -
Total fair value of options vested (000's)	$ 275	$ -
Total intrinsic value of options exercised (000's)	$ -	$ -

Share-based Payment Arrangement, Option, Exercise Price Range [Table Text Block]

	Outstanding Options			Exercisable		
Range of stock option prices	Number Outstanding	Weighted average remaining life	Weighted average exercise price	Number Outstanding	Weighted average remaining life	Weighted average exercise price
19.40-29.99	12,700	2.9	$ 22.61	12,700	2.9	$ 22.61
30.00-39.99	5,350	5.4	$ 37.47	5,350	5.4	$ 37.47
40.00-49.99	6,228	1.4	$ 47.79	6,228	1.4	$ 47.79
50.00-59.99	8,900	4.2	$ 57.16	8,900	4.2	$ 57.16
60.00-69.99	7,594	2.2	$ 63.24	7,594	2.2	$ 63.24
70.00-79.99	6,500	2.6	$ 73.57	6,500	2.6	$ 73.57
80.00-89.99	1,500	5.5	$ 86.40	1,500	5.5	$ 86.40
90.00-99.99	3,000	5.9	$ 90.10	3,000	5.9	$ 890.10
100.00-125.60	2,450	2.3	$ 107.97	2,450	2.3	$ 107.67
	54,222	3.3	$ 53.79	54,222	3.3	$ 53.79

Schedule of Nonvested Restricted Stock Units Activity [Table Text Block]

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2019	89	$ 31.67
Granted	-	-
Vested/Released	(33)	32.11
Forfeited/Expired	(15)	31.52
Unvested December 31, 2020	41	$ 31.37
Granted	-	-
Vested/Released	(24)	33.23
Forfeited/Expired	(3)	32.07
Unvested December 31, 2021	14	$ 27.97

Schedule of Nonvested Performance-based Units Activity [Table Text Block]

	Number of Shares	Weighted average grant date fair value
Unvested December 31, 2019	57	33.86
Granted	-	-
Vested/Released	-	-
Forfeited	(13)	34.29
Unvested December 31, 2020	44	$ 33.73
Granted	-	-

Vested/Released	-		-
Forfeited	(16)		45.73
Unvested December 31, 2021	28	$	26.80

Note 7 - Income Taxes (Tables)	12 Months Ended Dec. 31, 2021

Notes Tables

Schedule of Deferred Tax Assets and Liabilities [Table Text Block]

	As of December 31, 2020	2021
	(In thousands)	
Deferred tax liabilities:		
Hedge contracts	$ 4,299	$ -
Other	2,137	2,855
Total deferred tax liabilities	6,436	2,855
Deferred tax assets:		
US full cost pool	$ 35,500	24,464
Depletion carryforward	461	470
U.S. net operating loss carryforward	84,927	96,120
Alternative minimum tax credit	-	-
Hedge contracts	-	100
Interest disallowed	2,818	5,781
Total deferred tax assets	123,706	126,935
Valuation allowance for deferred tax assets	(117,270)	(124,080)
Net deferred tax assets	6,436	2,855
Net deferred tax	$ -	$ -

Schedule of Components of Income Tax Expense (Benefit) [Table Text Block]

	Years Ended December 31, 2020	2021
	(In thousands)	
Current:		
Federal	$ -	$ -
State	-	-
	$ -	$ -
Deferred:		
Federal	$ -	$ -
	$ -	$ -

Schedule of Effective Income Tax Rate Reconciliation [Table Text Block]

	Years Ended December 31, 2020	2021
	(in thousands)	
Tax benefit at U.S. Statutory rates	$ 38,749	$ 9,359
Change in deferred tax asset valuation allowance	(37,193)	(7,007)
Alternative minimum tax expense	-	-
Adjustment to deferred tax assets	-	(3,421)
Permanent differences	(276)	368
Return to provision estimated revision	(3,069)	-
State income taxes, net of federal effect	1,789	688
Other	-	13
	$ -	$ -

Note 9 - Earnings Per Share (Tables)	12 Months Ended Dec. 31, 2021
Notes Tables	
Schedule of Earnings Per Share, Basic and Diluted [Table Text Block]	(see table below)

	Years Ended December 31, 2020	Years Ended December 31, 2021
Numerator:		
Net loss	$ (184,522)	$ (44,567)
Denominator for basic earnings per share - weighted-average common shares outstanding	8,382	8,408
Effect of dilutive securities: Stock options, restricted shares and performance based shares	-	-
Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares	8,382	8,408
Net loss per common share - basic	$ (22.01)	$ (5.30)
Net loss per common share - diluted	$ (22.01)	$ (5.30)

Note 11 - Hedging Program and Derivatives (Tables)

12 Months Ended Dec. 31, 2021

Notes Tables

Schedule of Derivative Instruments in Statement of Financial Position, Fair Value [Table Text Block]

Fair Value Derivative Contracts as of December 31, 2020

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$ 9,639	Derivatives - current	$ 480
Commodity price derivatives	Derivatives - long-term	10,281	Derivatives - long-term	-
		$19,920		$ 480

Fair Value Derivative Contracts as of December 31, 2021

	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Commodity price derivatives	Derivatives - current	$ -	Derivatives - current	$ 442
		$ -		$ 442

Note 12 - Financial Instruments (Tables)

12 Months Ended Dec. 31, 2021

Notes Tables

Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis [Table Text Block]

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2020
Assets:				
NYMEX fixed price derivative contracts	$ -	$ 19,920	$ -	$ 19,920
Total Assets	$ -	$ 19,920	$ -	$ 19,920
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 480	$ -	$ 480
Total Liabilities	$ -	$ 480	$ -	$ 480

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2021
Assets:				
NYMEX fixed price derivative contracts	$ -	$ -	$ -	$ -
Total Assets	$ -	$ -	$ -	$ -
Liabilities:				
NYMEX fixed price derivative contracts	$ -	$ 442	$ -	$ 442
Total Liabilities	$ -	$ 442	$ -	$ 442

Note 13 - Lease Accounting Standard (Tables)

Notes Tables	12 Months Ended Dec. 31, 2021

Notes Tables

Lease, Cost [Table Text Block]

	For the Year Ended December 31, 2020	2021
	(in thousands)	
Operating lease cost	$ 114	$ 65
Short-term lease expense (1)	2,183	1,913
Total lease expense	$ 2,297	$ 1,978
Short-term lease costs (2)	$ 973	$ -

	For the Year Ended December 31, 2020	2021
	(in thousands)	
Weighted Average Remaining Lease Term (in years)	10.68	12.46
Weighted Average Discount Rate	6%	6%

	For the Year Ended December 31, 2020	2021
	(in thousands)	
Cash paid for amounts included in the measurement of lease liabilities	$ 114	$ 65
Right of Use assets added in exchange for lease obligations (since adoption)	$ 125	$ -

Schedule of Operating Leased Assets [Table Text Block]

	For the Year Ended December 31, 2020	2021
	(in thousands)	
Operating lease Right of Use asset	$ 228	$ 173
Operating lease liability - current	$ 53	$ 40
Operating lease liabilities - long-term	$ 150	$ 110

Lessee, Operating Lease, Liability, Maturity [Table Text Block]

	Operating Leases
	(in thousands)
2022	40
2023	41
2024	28
2025	4
2026	4
Thereafter	94
Total lease payments	211
Less imputed interest	(61)
Total lease liability	$ 150

Note 16 - Supplemental Oil and Gas Disclosures (Unaudited) (Tables)

12 Months Ended Dec. 31, 2021

Notes Tables

Capitalized Costs Relating to Oil and Gas Producing Activities Disclosure [Table Text Block]

	Years Ended December 31, (in thousands) 2020	2021
Proved oil and gas properties	$ 1,167,333	$ 1,165,707
Unproved properties	-	-
Total	1,167,333	1,165,707
Accumulated depreciation, depletion, amortization and impairment	(1,060,649)	(1,074,144)
Net capitalized costs	$ 106,684	$ 91,563

Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure [Table Text Block]

	2020	2021
Development costs	$ 5,238	$ 1,145
Exploration costs	-	-
Property acquisition costs	-	-
	$ 5,238	$ 1,145

Results of Operations for Oil and Gas Producing Activities Disclosure [Table Text Block]

	2020	2021
Revenues	$ 42,984	$ 78,836
Production costs	(21,090)	(24,137)
Depreciation, depletion and amortization	(22,679)	(13,495)
Accretion of future site restoration	(414)	(330)
Proved property impairment	(186,980)	-
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$(188,179)	$ 40,874
Depletion rate per barrel of oil equivalent	$ 12.58	$ 6.67

Schedule of Proved Developed and Undeveloped Oil and Gas Reserve Quantities [Table Text Block]

	Total Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Oil Equivalents (Mboe)
Proved Developed Reserves:				
December 31, 2020	9,538	3,187	24,318	16,778
December 31, 2021	6,883	2,914	30,158	14,823
Proved Undeveloped Reserves:				
December 31, 2020	-	-	-	-
December 31, 2021	-	-	-	-

Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Table Text Block]

	Years Ended December 31, (in thousands)	
	2020	2021
Future cash inflows	$ 345,869	$ 485,982
Future production costs	(166,781)	(222,309)
Future development costs	(6,291)	(5,623)
Future income tax expense	-	-
Future net cash flows	172,797	258,050
Discount	$ (66,113)	$(104,775)
Standardized Measure of discounted future net cash relating to proved reserves	$ 106,684	$ 153,275

Note 1 - Organization and Significant Accounting Policies (Details Textual) $ in Thousands	Oct. 19, 2020	12 Months Ended Dec. 31, 2021 USD ($)	12 Months Ended Dec. 31, 2020 USD ($)	21852 Months Ended Dec. 31, 2021 USD ($)
Accounts Receivable, Allowance for Credit Loss, Ending Balance		$ 100	$ 100	$ 100
Number of Operating Segments		1		
Discount Rate Used in Future Net Cash Flows Relating to Proved Oil and Gas Reserves				10.00%
Impairment of Oil and Gas Properties		$ 0	186,980	
Share-based Payment Arrangement, Noncash Expense, Total		946	1,312	
Deferred Tax Assets, Valuation Allowance, Total		124,080	$ 117,270	$ 124,080
Unrecognized Tax Benefits, Ending Balance		$ 0		0
Revenue Benchmark [Member] | Customer Concentration Risk [Member]				
Entity Wide Revenue Number of Major Purchasers of Oil and Gas		4	4	
Revenue Benchmark [Member] | Customer Concentration Risk [Member] | Four Purchasers [Member]				
Concentration Risk, Percentage		83.00%	73.00%	
Non-US [Member]				
Long-Lived Assets		$ 0		$ 0
Reverse Stock Split [Member]				
Stockholders' Equity Note, Stock Split, Conversion Ratio	20			

Note 1 - Organization and Significant Accounting Polcies - Future Site Restoration Obligation (Details) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Beginning future site restoration obligation	$ 7,360	$ 7,420
New wells placed on production and other	1	43
Deletions related to property disposals	(2,845)	(216)
Deletions related to plugging costs	(342)	(235)
Accretion expense and other	330	414
Revisions and other	204	(66)
Ending future site restoration obligation	$ 4,708	$ 7,360

Note 2 - Revenue From Contracts With Customers (Details Textual) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Gas Balancing Asset (Liability)	$ 0	$ 0
Contract with Customer, Asset, after Allowance for Credit Loss, Total	$ 12,300	$ 8,800

Note 2 - Revenue From Contracts With Customers - Disaggregation of Revenue (Details) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Oil Revenues [Member]		
Revenue	$ 61,228	$ 41,969
Gas Revenues [Member]		
Revenue	8,656	586
Natural Gas Liquids Revenues [Member]		
Revenue	8,952	429
Permian / Delaware Basin [Member] | Oil Revenues [Member]		
Revenue	32,666	22,891
Permian / Delaware Basin [Member] | Gas Revenues [Member]		
Revenue	4,474	335
Permian / Delaware Basin [Member] | Natural Gas Liquids Revenues [Member]		
Revenue	2,181	163
Rocky Mountain [Member] | Oil Revenues [Member]		
Revenue	[1] 28,562	19,078
Rocky Mountain [Member] | Gas Revenues [Member]		
Revenue	[1] 4,182	251
Rocky Mountain [Member] | Natural Gas Liquids Revenues [Member]		
Revenue	[1] $ 6,771	$ 266

[1] All Rocky Mountain assest sold January 3, 2022.

Note 3 - Reverse Stock Split (Details Textual) $ / shares in Units, $ in Millions	Oct. 19, 2020 $ / shares shares	3 Months Ended Sep. 30, 2020 USD ($)	12 Months Ended Dec. 31, 2019 USD ($)	Dec. 31, 2021 $ / shares shares	Dec. 31, 2020 $ / shares shares	Oct. 18, 2020 shares
Common Stock, Par or Stated Value Per Share (in dollars per share) | $ / shares				$ 0.01	$ 0.01	
Common Stock, Shares Authorized (in shares)				20,000,000	20,000,000	
Common Stock, Shares, Outstanding, Ending Balance (in shares)				8,421,910	8,421,910	
Reverse Stock Split [Member]						
Stockholders' Equity Note, Stock Split, Conversion Ratio	20					
Common Stock, Par or Stated Value Per Share (in dollars per share) | $ / shares	$ 0.01					
Common Stock, Shares Authorized (in shares)	20,000,000					400,000,000
Common Stock, Shares, Outstanding, Ending Balance (in shares)	8,453,466					168,069,305
Adjustments to Additional Paid in Capital, Stock Split | $		$ 1.6	$ 1.6			

Note 4 - Long-term Debt (Details Textual)					9 Months Ended	12 Months Ended		
	Nov. 22, 2021 USD ($)	Oct. 19, 2020 USD ($) $ / shares shares	Jun. 25, 2020 USD ($)	Nov. 13, 2019 USD ($)	Sep. 30, 2021	Dec. 31, 2021 USD ($)	Dec. 31, 2020 USD ($)	Aug. 11, 2020 $ / shares shares
Long-term Debt, Total						$ 2,205,000	$ 2,515,000	
Reverse Stock Split [Member]								
Stockholders' Equity Note, Stock Split, Conversion Ratio		20						
Warrant Issued to Lender [Member]								
Class of Warrant or Right, Number of Securities Called by Warrants or Rights (in shares) | shares		1,672,290						33,445,792
Class of Warrant or Right, Exercise Price of Warrants or Rights (in dollars per share) | $ / shares		$ 0.20						$ 0.01
Warrants and Rights Outstanding, Term (Year)		5 years						
Gain (Loss) on Cancellation of Warrant	$ (2,500,000)							
Second Lien Credit Facility [Member]								
Gain (Loss) on Extinguishment of Debt, Total						(0)	(4,108,000)	
Line of Credit [Member] | First Lien Credit Facility [Member]								
Long-term Line of Credit, Total						$ 71,400,000		
Debt Instrument, Spread on Elected Variable Rate						0.50%		
Debt Instrument, Debt Default, Basis Spread on Variable Rate					3.00%	3.00%		
Line of Credit Facility, Interest Rate at Period End						8.75%		
Debt Instrument, Collateral Eligible, Minimum Percent of PV-9 of Proven Reserves Required						90.00%		
Debt Instrument, Collateral Eligible, Minimum Percent of PV-9 of PDP Reserves Required						95.00%		
Debt Instrument, Covenant, Working Capital Reserve			$ 3,000,000.0					

Debt Instrument, Covenant, Maximum Capital Expenditures	$ 3,000,000.0	
Debt Instrument, Covenant, Minimum Asset Coverage Ratio for Capital Expenditures	1.60	
Debt Instrument, Covenant, Maximum Line of Credit Outstanding for Capital Expenditures	$ 50,000,000.0	
Debt Instrument, Covenant, Maximum Outstanding and Undisputed Accounts Payable	7,500,000	
Debt Instrument, Covenant, Maximum Undisputed Accounts Payable Outstanding with 60 to 90 Days	2,000,000.0	
Debt Instrument, Covenant, Maximum Undisputed Accounts Payable Outstanding with Over 90 Days	1,000,000.0	
Debt Instrument, Covenant, Maximum Legal and Professional Fees Excluded from General and Administrative Expense Limitations	1,000,000.0	
Debt Instrument, Covenant, Maximum Additional Subordinated Debt Allowed to Finance Capital Expenditures	25,000,000.0	
Line of Credit Facility, Current Borrowing Capacity	102,000,000.0	
Line of Credit Facility, Remaining Borrowing Capacity		$ 0
Line of Credit [Member] | First Lien Credit Facility [Member] | General and Administrative Expenses for Quarter Ending June 30, 2020 [Member]		
Debt Instrument, Covenant, Maximum Quarterly General and Administrative Expenses	9,000,000.0	
Line of Credit [Member] | First Lien Credit Facility [Member] | General and Administrative Expenses for Quarter Ending September 30, 2020 [Member]		
Debt Instrument, Covenant, Maximum Quarterly General and Administrative Expenses	8,250,000	

Line of Credit [Member] | First Lien Credit Facility [Member] | General and Administrative Expenses for Quarter Ending December 31, 2020 [Member]		
Debt Instrument, Covenant, Maximum Quarterly General and Administrative Expenses	6,900,000	
Line of Credit [Member] | First Lien Credit Facility [Member] | General and Administrative Expenses for Year End December 31, 2021 [Member]		
Debt Instrument, Covenant, Maximum Yearly General and Administrative Expenses	6,500,000	
Line of Credit [Member] | First Lien Credit Facility [Member] | General and Administrative Expenses After Year End December 31, 2021 [Member]		
Debt Instrument, Covenant, Maximum Yearly General and Administrative Expenses	$ 5,000,000.0	
Line of Credit [Member] | First Lien Credit Facility [Member] | Minimum [Member]		
Debt Instrument, Spread on Elected Variable Rate		2.50%
Debt Instrument, Basis Spread on Variable Rate		1.50%
Line of Credit [Member] | First Lien Credit Facility [Member] | Maximum [Member]		
Debt Instrument, Spread on Elected Variable Rate		3.50%
Debt Instrument, Basis Spread on Variable Rate		2.50%
Debt Instrument, Covenant, Total Debt to EBITDAX Ratio	2.75	
Debt Instrument, Covenant, Asset Coverage Ratio, Current	1.15	
Debt Instrument, Covenant, Asset Coverage Ratio, Noncurrent	1.25	
Line of Credit [Member] | Second Lien Credit Facility [Member]		

Long-term Line of Credit, Total				$ 144,900,000	
Debt Instrument, Covenant, Maximum Outstanding and Undisputed Accounts Payable		$ 7,500,000			
Debt Instrument, Covenant, Maximum Undisputed Accounts Payable Outstanding with 60 to 90 Days		2,000,000.0			
Debt Instrument, Covenant, Maximum Undisputed Accounts Payable Outstanding with Over 90 Days		1,000,000.0			
Line of Credit Facility, Maximum Borrowing Capacity			$ 100,000,000.0		
Proceeds from Lines of Credit, Total			$ 95,000,000.0		
Line of Credit, Exit Fee				$ 10,000,000	$ 10,000,000
Debt Instrument, Collateral Eligible, Minimum Percent of PV-9 Proven Reserves					90.00%
Debt Instrument, Collateral Eligible, Minimum Percent of PV-9 Required PDP Reserves					95.00%
Gain (Loss) on Extinguishment of Debt, Total	$ 4,100,000				
Line of Credit [Member] | Second Lien Credit Facility [Member] | General and Administrative Expenses for Quarter Ending June 30, 2020 [Member]					
Debt Instrument, Covenant, Maximum Quarterly General and Administrative Expenses		9,000,000.0			
Line of Credit [Member] | Second Lien Credit Facility [Member] | General and Administrative Expenses for Quarter Ending September 30, 2020 [Member]					
Debt Instrument, Covenant, Maximum Quarterly General and Administrative Expenses		8,250,000			
Line of Credit [Member] | Second Lien Credit Facility [Member] | General and Administrative Expenses for Year End December 31, 2021 [Member]					

Debt Instrument, Covenant, Maximum Yearly General and Administrative Expenses	6,500,000		
Line of Credit [Member] | Second Lien Credit Facility [Member] | General and Administrative Expenses After Year End December 31, 2021 [Member]			
Debt Instrument, Covenant, Maximum Yearly General and Administrative Expenses	$ 5,000,000.0		
Line of Credit [Member] | Second Lien Credit Facility [Member] | Maximum [Member]			
Debt Instrument, Covenant, Asset Coverage Ratio, Noncurrent, Year Two	1.45		
Debt Instrument, Covenant, Asset Coverage Ratio, Noncurrent, after Year Two	1.55		
Construction Loans [Member]			
Debt Instrument, Interest Rate, Stated Percentage		4.90%	
Debt Instrument, Periodic Payment, Total		$ 35,672	
Long-term Debt, Total		$ 2,500,000	$ 2,800,000

Note 4 - Long-term Debt - Debt (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Long-term debt	$ 218,822	$ 220,505
Less current maturities	(212,688)	(202,751)
Long-term Debt, Noncurrent, Gross	6,134	17,754
Deferred financing fees and debt issuance cost - net	(3,929)	(15,239)
Total long-term debt, net of deferred financing fees and debt issuance costs	2,205	2,515
Line of Credit [Member] | First Lien Credit Facility [Member]		
Long-term debt	71,400	95,000
Line of Credit [Member] | Second Lien Credit Facility [Member]		
Long-term debt	134,907	112,695
Exit fee - Second Lien Credit Facility	10,000	10,000
Mortgages [Member]		
Long-term debt	$ 2,515	$ 2,810

Note 4 - Long-term Debt - Maturities of Long-term Debt (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
2022	$ 216,617	
2023	2,205	
2025	0	
2026	0	
Thereafter	0	
Total	$ 218,822	$ 220,505

Note 5 - Property and Equipment - Property and Equipment (Details) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Oil and gas properties (1)	$ 1,205,044	$ 1,206,789
Accumulated depreciation, depletion, amortization and impairment	(1,099,075)	(1,083,843)
Net Property and Equipment	105,969	122,946
Oil and Gas Properties [Member]		
Oil and gas properties (1)	[1] 1,165,707	1,167,333
Equipment and Other [Member]		
Oil and gas properties (1)	$ 15,257	15,348
Equipment and Other [Member] | Minimum [Member]		
Estimated Useful Life (Year)	3 years	
Equipment and Other [Member] | Maximum [Member]		
Estimated Useful Life (Year)	39 years	
Drilling Rig [Member]		
Oil and gas properties (1)	$ 24,080	$ 24,108
Estimated Useful Life (Year)	15 years	

[1] Oil and gas properties are amortized utilizing the units of production method.

Note 6 - Stock-based Compensation and Option Plans (Details Textual) - USD ($)		12 Months Ended	
	Apr. 01, 2018	Dec. 31, 2021	Dec. 31, 2020
Common Stock, Capital Shares Reserved for Future Issuance (in shares)		1,900,000	
Share-based Compensation Arrangement by Share-based Payment Award, Options, Grants in Period, Gross (in shares)		0	0
Share-based Payment Arrangement, Noncash Expense, Total		$ 946,000	$ 1,312,000
Directors Plan 2005 [Member]			
Common Stock, Capital Shares Reserved for Future Issuance (in shares)		70,000,000	
Share-based Compensation Arrangement by Share-based Payment Award, Maximum Number of Shares Per Employee (in shares)		1,250	
Percentage of Exercise Price Awarded		100.00%	
Share-based Payment Arrangement, Option [Member]			
Common Stock, Capital Shares Reserved for Future Issuance (in shares)		1,683,639,000,000	
Share-based Compensation Arrangement by Share-based Payment Award, Expiration Period (Year)		10 years	
Share-based Payment Arrangement, Nonvested Award, Cost Not yet Recognized, Amount, Total		$ 0	
Share-based Payment Arrangement, Noncash Expense, Total		0	100,000
Restricted Stock [Member]			
Share-based Payment Arrangement, Noncash Expense, Total		600,000	$ 900,000
Share-based Payment Arrangement, Nonvested Award, Excluding Option, Cost Not yet Recognized, Amount		$ 100,000	
Share-based Compensation Arrangement by Share-based Payment Award, Equity Instruments Other than Options, Vested in Period (in shares)		24	33
Restricted Stock [Member] | Directors Plan 2005 [Member] | Share-based Payment Arrangement, Nonemployee [Member]			
Share-based Compensation Arrangement by Share-based Payment Award, Equity Instruments Other than Options, Amount Approved for Issuance Per Participant		$ 12,000	
Performance Shares [Member]			
Share-based Payment Arrangement, Noncash Expense, Total		200,000	$ 200,000
Share-based Payment Arrangement, Nonvested Award, Excluding Option, Cost Not yet Recognized, Amount		$ 100,000	
Share-based Compensation Arrangement by Share-based Payment Award, Award Vesting Period (Year)	3 years		
Share-based Compensation Arrangement by Share-based Payment Award, Equity Instruments Other than Options, Vested in Period (in shares)		(0)	(0)
Share-based Compensation Arrangement by Share-based Payment Award, Fair Value Assumptions, Target Payout Rate		100.00%	
Performance Shares [Member] | Minimum [Member]			
Share-based Compensation Awards, Vesting, Requirement, TSR, Percentage	0.00%		

Performance Shares [Member] | Maximum [Member]	
Share-based Compensation Awards, Vesting, Requirement, TSR, Percentage	200.00%

Note 6 - Stock-based Compensation and Option Plans - Stock Option Activity (Details) - Share-based Payment Arrangement, Option [Member] - USD ($) $ / shares in Units, shares in Thousands, $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Balance (in shares)	196	297
Balance, weighted average exercise price (in dollars per share)	$ 49.69	$ 49.41
Forfeited/Expired (in shares)	(141)	(101)
Forfeited/Expired, weighted average exercise price (in dollars per share)	$ 48.11	$ 48.96
Balance (in shares)	55	196
Balance, weighted average exercise price (in dollars per share)	$ 53.79	$ 49.69
Options outstanding, weighted average remaining life (Year)	3 years 3 months 18 days	
Options outstanding, intrinsic value per share (in dollars per share)	$ 0.00	
Exercisable at end of year (in shares)	55	
Exercisable, weighted average exercise price (in dollars per share)	$ 53.79	
Exercisable, weighted average remaining life (Year)	3 years 3 months 18 days	
Exercisable, intrinsic value per share (in dollars per share)	$ 0.00	
Weighted average grant date fair value of stock options granted (per share) (in dollars per share)	$ 0	$ 0
Total fair value of options vested (000's)	$ 0	$ 275
Total intrinsic value of options exercised (000's)	$ 0	$ 0

Note 6 - Stock-based Compensation and Option Plans - Stock Options Outstanding (Details)	12 Months Ended Dec. 31, 2021 $ / shares shares
Outstanding options, number outstanding (in shares) | shares	54,222
Outstanding options, weighted average remaining life (Year)	3 years 3 months 18 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 53.79
Exercisable, number outstanding (in shares) | shares	54,222
Exercisable, weighted average remaining life (Year)	3 years 3 months 18 days
Exercisable, weighted average exercise price (in dollars per share)	$ 53.79
Range One [Member]	
Exercise price range, lower limit (in dollars per share)	19.40
Exercise price range, upper limit (in dollars per share)	$ 29.99
Outstanding options, number outstanding (in shares) | shares	12,700
Outstanding options, weighted average remaining life (Year)	2 years 10 months 24 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 22.61
Exercisable, number outstanding (in shares) | shares	12,700
Exercisable, weighted average remaining life (Year)	2 years 10 months 24 days
Exercisable, weighted average exercise price (in dollars per share)	$ 22.61
Range Two [Member]	
Exercise price range, lower limit (in dollars per share)	30.00
Exercise price range, upper limit (in dollars per share)	$ 39.99
Outstanding options, number outstanding (in shares) | shares	5,350
Outstanding options, weighted average remaining life (Year)	5 years 4 months 24 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 37.47
Exercisable, number outstanding (in shares) | shares	5,350
Exercisable, weighted average remaining life (Year)	5 years 4 months 24 days
Exercisable, weighted average exercise price (in dollars per share)	$ 37.47
Range Three [Member]	
Exercise price range, lower limit (in dollars per share)	40.00
Exercise price range, upper limit (in dollars per share)	$ 49.99
Outstanding options, number outstanding (in shares) | shares	6,228
Outstanding options, weighted average remaining life (Year)	1 year 4 months 24 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 47.79
Exercisable, number outstanding (in shares) | shares	6,228
Exercisable, weighted average remaining life (Year)	1 year 4 months 24 days
Exercisable, weighted average exercise price (in dollars per share)	$ 47.79
Range Four [Member]	
Exercise price range, lower limit (in dollars per share)	50.00
Exercise price range, upper limit (in dollars per share)	$ 59.99
Outstanding options, number outstanding (in shares) | shares	8,900
Outstanding options, weighted average remaining life (Year)	4 years 2 months 12 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 57.16

Exercisable, number outstanding (in shares) | shares	8,900
Exercisable, weighted average remaining life (Year)	4 years 2 months 12 days
Exercisable, weighted average exercise price (in dollars per share)	$ 57.16
Range Five [Member]	
Exercise price range, lower limit (in dollars per share)	60.00
Exercise price range, upper limit (in dollars per share)	$ 69.99
Outstanding options, number outstanding (in shares) | shares	7,594
Outstanding options, weighted average remaining life (Year)	2 years 2 months 12 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 63.24
Exercisable, number outstanding (in shares) | shares	7,594
Exercisable, weighted average remaining life (Year)	2 years 2 months 12 days
Exercisable, weighted average exercise price (in dollars per share)	$ 63.24
Range Six [Member]	
Exercise price range, lower limit (in dollars per share)	70.00
Exercise price range, upper limit (in dollars per share)	$ 79.99
Outstanding options, number outstanding (in shares) | shares	6,500
Outstanding options, weighted average remaining life (Year)	2 years 7 months 6 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 73.57
Exercisable, number outstanding (in shares) | shares	6,500
Exercisable, weighted average remaining life (Year)	2 years 7 months 6 days
Exercisable, weighted average exercise price (in dollars per share)	$ 73.57
Range Seven [Member]	
Exercise price range, lower limit (in dollars per share)	80.00
Exercise price range, upper limit (in dollars per share)	$ 89.99
Outstanding options, number outstanding (in shares) | shares	1,500
Outstanding options, weighted average remaining life (Year)	5 years 6 months
Outstanding options, weighted average exercise price (in dollars per share)	$ 86.40
Exercisable, number outstanding (in shares) | shares	1,500
Exercisable, weighted average remaining life (Year)	5 years 6 months
Exercisable, weighted average exercise price (in dollars per share)	$ 86.40
Range Eight [Member]	
Exercise price range, lower limit (in dollars per share)	90.00
Exercise price range, upper limit (in dollars per share)	$ 99.99
Outstanding options, number outstanding (in shares) | shares	3,000
Outstanding options, weighted average remaining life (Year)	5 years 10 months 24 days
Outstanding options, weighted average exercise price (in dollars per share)	$ 90.10
Exercisable, number outstanding (in shares) | shares	3,000
Exercisable, weighted average remaining life (Year)	5 years 10 months 24 days
Exercisable, weighted average exercise price (in dollars per share)	$ 890.10
Range Nine [Member]	
Exercise price range, lower limit (in dollars per share)	100.00
Exercise price range, upper limit (in dollars per share)	$ 125.60
Outstanding options, number outstanding (in shares) | shares	2,450
Outstanding options, weighted average remaining life (Year)	2 years 3 months 18 days

Outstanding options, weighted average exercise price (in dollars per share)	$ 107.97
Exercisable, number outstanding (in shares) | shares	2,450
Exercisable, weighted average remaining life (Year)	2 years 3 months 18 days
Exercisable, weighted average exercise price (in dollars per share)	$ 107.67

Note 6 - Stock-based Compensation and Option Plans - Restricted Stock Activity (Details) - Restricted Stock [Member] - $ / shares	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Unvested (in shares)	41	89
Unvested, weighted average grant date fair value (in dollars per share)	$ 31.37	$ 31.67
Granted (in shares)	0	0
Granted, weighted average grant date fair value (in dollars per share)	$ 0	$ 0
Vested/Released (in shares)	(24)	(33)
Vested/Released, weighted average grant date fair value (in dollars per share)	$ 33.23	$ 32.11
Forfeited/Expired (in shares)	(3)	(15)
Forfeited/Expired, weighted average grant date fair value (in dollars per share)	$ 32.07	$ 31.52
Unvested (in shares)	14	41
Unvested, weighted average grant date fair value (in dollars per share)	$ 27.97	$ 31.37

Note 6 - Stock-based Compensation and Option Plans - Performance Based Restricted Stock Awards (Details) - Performance Shares [Member] - $ / shares	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Unvested (in shares)	44	57
Unvested, weighted average grant date fair value (in dollars per share)	$ 33.73	$ 33.86
Granted (in shares)	0	0
Granted, weighted average grant date fair value (in dollars per share)	$ 0	$ 0
Vested/Released (in shares)	0	0
Vested/Released, weighted average grant date fair value (in dollars per share)	$ 0	$ 0
Forfeited/Expired (in shares)	(16)	(13)
Forfeited/Expired, weighted average grant date fair value (in dollars per share)	$ 45.73	$ 34.29
Unvested (in shares)	28	44
Unvested, weighted average grant date fair value (in dollars per share)	$ 26.80	$ 33.73

Note 7 - Income Taxes (Details Textual) - USD ($) $ in Thousands	12 Months Ended Dec. 31, 2021	Dec. 31, 2020
Deferred Tax Assets, Valuation Allowance, Total	$ 124,080	$ 117,270
Unrecognized Tax Benefits, Income Tax Penalties and Interest Accrued, Total	$ 0	$ 0
Effective Income Tax Rate Reconciliation, at Federal Statutory Income Tax Rate, Percent	21.00%	
Pre 2018 [Member] | Domestic Tax Authority [Member] | Internal Revenue Service (IRS) [Member]		
Operating Loss Carryforwards, Total	$ 245,200	
Post 2018 [Member] | Domestic Tax Authority [Member] | Internal Revenue Service (IRS) [Member]		
Operating Loss Carryforwards, Total	$ 190,800	
Earliest Tax Year [Member]		
Operating Loss Carryforwards, Expiration Date	Dec. 31, 2022	
Latest Tax Year [Member]		
Operating Loss Carryforwards, Expiration Date	Dec. 31, 2037	

Note 7 - Income Taxes - Deferred Tax Liabilities and Assets (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Hedge contracts	$ 0	$ 4,299
Other	2,855	2,137
Total deferred tax liabilities	2,855	6,436
US full cost pool	24,464	35,500
Depletion carryforward	470	461
U.S. net operating loss carryforward	96,120	84,927
Alternative minimum tax credit	0	0
Hedge contracts	100	0
Interest disallowed	5,781	2,818
Total deferred tax assets	126,935	123,706
Valuation allowance for deferred tax assets	(124,080)	(117,270)
Net deferred tax assets	2,855	6,436
Net deferred tax	$ 0	$ 0

Note 7 - Income Taxes - Provision (Benefit) for Income Taxes (Details) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Federal	$ 0	$ 0
State	0	0
Federal	$ 0	$ 0

Note 7 - Income Taxes - Reconciliation of Income Tax (Details) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Tax benefit at U.S. Statutory rates	$ 9,359	$ 38,749
Change in deferred tax asset valuation allowance	(7,007)	(37,193)
Alternative minimum tax expense	0	0
Adjustment to deferred tax assets	(3,421)	0
Permanent differences	368	(276)
Return to provision estimated revision	0	(3,069)
State income taxes, net of federal effect	688	1,789
Other	$ 13	$ 0

Note 9 - Earnings Per Share - Computation of Basic and Diluted Earnings Per Share (Details) - USD ($) $ / shares in Units, shares in Thousands, $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Net loss	$ (44,567)	$ (184,522)
Basic (in shares)	8,408	8,382
Effect of dilutive securities: Stock options, restricted shares and performance based shares (in shares)	0	0
Denominator for diluted earnings per share - adjusted weighted-average shares and assumed exercise of options, restricted shares and performance based shares (in shares)	8,408	8,382
Net loss per common share - basic (in dollars per share)	$ (5.30)	$ (22.01)
Net loss per common share - diluted (in dollars per share)	$ (5.30)	$ (22.01)

Note 10 - Benefit Plans (Details Textual)	12 Months Ended		
	Dec. 31, 2022 USD ($)	Dec. 31, 2021 USD ($)	Dec. 31, 2020 USD ($)
Deferred Compensation Arrangement with Individual, Contributions by Employer		$ 123,639	$ 142,820
Defined Contribution Plan, Employer Matching Contribution, Percent of Employees' Gross Pay			1.00%
Defined Contribution Plan, Employer Matching Contribution, Amount of Cents Per Dollar Increase for Each Additional Percentage Point		50	
Defined Contribution Plan, Maximum Annual Contributions Per Employee, Percent		5.00%	
Defined Contribution Plan Employee Contribution Limit Below 50 Years of Age		$ 19,500	
Defined Contribution Plan Employee Contribution Limit 50 Years of Age or Older		$ 26,000	
Forecast [Member]			
Deferred Compensation Arrangement with Individual, Contributions by Employer	$ 1,637		

Note 11 - Hedging Program and Derivatives (Details Textual) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Derivative Liability, Total	$ 442	$ 480
Commodity Contract [Member]		
Derivative Liability, Total	400	
Commodity Contract [Member] | (Gain) Loss on Derivative Contracts [Member]		
Gain (Loss) on Sale of Derivatives	(33,000)	$ 42,900
Commodity Closed Contracts [Member] | (Gain) Loss on Derivative Contracts [Member]		
Gain (Loss) on Sale of Derivatives	$ (7,100)	

Note 11 - Hedging Program and Derivatives - Impact of Derivative Contracts on Balance Sheet (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Derivative asset, current	$ 0	$ 9,639
Derivative liability, current	442	480
Derivative asset, long-term	0	10,281
Derivative asset		19,920
Derivative Liability, Total	442	480
Commodity Contract [Member]		
Derivative Liability, Total	400	
Commodity Contract [Member] | Derivative Assets Current [Member]		
Derivative asset, current		9,639
Commodity Contract [Member] | Derivative Liabilities Current [Member]		
Derivative liability, current	$ 442	480
Commodity Contract [Member] | Derivative Assets Noncurrent [Member]		
Derivative asset, long-term		$ 10,281

Note 12 - Financial Instruments - Assets and Liabilities Measured at Fair Value on a Recurring Basis (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Derivative assets		$ 19,920
Derivative liabilities	$ 442	480
Fair Value, Recurring [Member]		
Derivative assets	0	19,920
Derivative liabilities	442	480
Fair Value, Recurring [Member] | Fixed Price Derivative Contracts [Member]		
Derivative assets	0	19,920
Derivative liabilities	442	480
Fair Value, Recurring [Member] | Fair Value, Inputs, Level 1 [Member]		
Derivative assets	0	0
Derivative liabilities	0	0
Fair Value, Recurring [Member] | Fair Value, Inputs, Level 1 [Member] | Fixed Price Derivative Contracts [Member]		
Derivative assets	0	0
Derivative liabilities	0	0
Fair Value, Recurring [Member] | Fair Value, Inputs, Level 2 [Member]		
Derivative assets	0	19,920
Derivative liabilities	442	480
Fair Value, Recurring [Member] | Fair Value, Inputs, Level 2 [Member] | Fixed Price Derivative Contracts [Member]		
Derivative assets	0	19,920
Derivative liabilities	442	480
Fair Value, Recurring [Member] | Fair Value, Inputs, Level 3 [Member]		
Derivative assets	0	0
Derivative liabilities	0	0
Fair Value, Recurring [Member] | Fair Value, Inputs, Level 3 [Member] | Fixed Price Derivative Contracts [Member]		
Derivative assets	0	0
Derivative liabilities	$ 0	$ 0

Note 13 - Lease Accounting Standard (Details Textual)	Dec. 31, 2021
Lease for Residence in North Dakota [Member]	
Lessee, Operating Lease, Term of Contract (Year)	5 years

Note 13 - Lease Accounting Standard - Total Lease Expense (Details) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Operating lease cost	$ 65	$ 114
Short-term lease expense	[1] 1,913	2,183
Total lease expense	$ 1,978	$ 2,297
Weighted Average Remaining Lease Term (Year)	12 years 5 months 15 days	10 years 8 months 4 days
Weighted Average Discount Rate	6.00%	6.00%
Cash paid for amounts included in the measurement of lease liabilities	$ 65	$ 114
Right of Use assets added in exchange for lease obligations (since adoption)	0	125
Drilling Rig [Member]		
Short-term lease expense	[2] $ 0	$ 973

[1] Short-term lease expense represents expense related to leases with a contract term of 12 months or less.

[2] These short-term lease costs are related to leases with a contract term of 12 months or less which are related to drilling rigs and are capitalized as part of natural gas and oil properties on our balance sheet.

Note 13 - Lease Accounting Standard - Balance Sheet Information (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Operating lease Right of Use asset	$ 173	$ 228
Operating lease liability - current	40	53
Operating lease liabilities - long-term	$ 110	$ 150

Note 13 - Lease Accounting Standard - Lease Liabilities Maturity (Details) $ in Thousands	Dec. 31, 2021 USD ($)
2022	$ 40
2023	41
2024	28
2025	4
2026	4
Thereafter	94
Total lease payments	211
Less imputed interest	(61)
Total lease liability	$ 150

Note 14 - Subsequent Events (Details Textual) - Subsequent Event [Member]	Jan. 03, 2022 USD ($) shares
Annual Rate pf Return, Percent	6.00%
Series A Preferred Stock [Member]	
Stock Issued During Period, Shares, New Issues (in shares) | shares	685,505
Capital Stock, Proceed Distribution Allocation, Percentage to Shares, Tier One	95.00%
Maximum Aggregate Proceeds Received Allowed, Tire One Preference Amount	$ 100,000,000
Maximum Aggregate Proceeds Received Allowed, Tire Two Preference Amount	$ 137,100,000
Capital Stock, Proceed Distribution Allocation, Percentage to Shares, Tier Three	75.00%
Number of Votes Each Share Entitled	69
Preferred Stock, Voting Power, Percent	85.00%
Common Stock [Member]	
Capital Stock, Proceed Distribution Allocation, Percentage to Shares, Tier One	5.00%
Capital Stock, Proceed Distribution Allocation, Percentage to Shares, Tier Three	25.00%
Lime Rock Resources V-A, L.P. [Member]	
Proceeds from Sale of Property, Plant, and Equipment, Total	$ 87,200,000
Proceeds from Sale of Property Plant and Equipment, after Customary Closing Adjustments	73,300,000
AGEF [Member]	
Maximum Additional Funding	$ 12,000,000.0

Note 15 - Events of Default (Details Textual) - USD ($) $ in Thousands	Dec. 31, 2021	Sep. 30, 2021	Apr. 16, 2021	Apr. 12, 2021	Dec. 31, 2020
Termination Value of Hedge Contracts	$ 8,022				$ 0
Morgan Stanley [Member]					
Termination Value of Hedge Contracts				$ 9,200	
Second Lien Credit Facility [Member]					
Debt Instrument, Interest Rate, Additional Default Interest			3.00%		
First Lien Credit Facility [Member] | Obligations from Terminated Hedging Arrangements [Member]					
Termination Value of Hedge Contracts		$ 9,200			
Debt Instrument, Interest Rate, Stated Percentage	0.00%				
First Lien Credit Facility [Member] | Morgan Stanley [Member]					
Percentage of Outstanding Obligations				3.70%	
First Lien Credit Facility [Member] | Morgan Stanley [Member] | Obligations from Terminated Hedging Arrangements [Member]					
Termination Value of Hedge Contracts		$ 8,400			

Note 16 - Supplemental Oil and Gas Disclosures (Unaudited) - Capitalized Costs (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Proved oil and gas properties	$ 1,165,707	$ 1,167,333
Unproved properties	0	0
Total	1,165,707	1,167,333
Accumulated depreciation, depletion, amortization and impairment	(1,074,144)	(1,060,649)
Net capitalized costs	$ 91,563	$ 106,684

Note 16 - Supplemental Oil and Gas Disclosures (Unaudited) - Cost Incurred (Details) - USD ($) $ in Thousands	12 Months Ended	
	Dec. 31, 2021	Dec. 31, 2020
Development costs	$ 1,145	$ 5,238
Exploration costs	0	0
Property acquisition costs	0	0
Costs Incurred, Acquisition of Oil and Gas Properties, Total	$ 1,145	$ 5,238

Note 16 - Supplemental Oil and Gas Disclosures (Unaudited) - Results of Operations (Details) $ in Thousands	12 Months Ended	
	Dec. 31, 2021 USD ($) $ / bbl	Dec. 31, 2020 USD ($) $ / bbl
Revenues	$ 78,836	$ 42,984
Production costs	(24,137)	(21,090)
Depreciation, depletion and amortization	(13,495)	(22,679)
Accretion of future site restoration	(330)	(414)
Proved property impairment	0	(186,980)
Results of operations from oil and gas producing activities (excluding corporate overhead and interest costs)	$ 40,874	$ (188,179)
Depletion rate per barrel of oil equivalent (in USD per Barrel of Oil) | $ / bbl	6.67	12.58

Note 16 - Supplemental Oil and Gas Disclosures (Unaudited) - Proved Developed and Undeveloped Reserves (2) (Details) - bbl bbl in Thousands	Dec. 31, 2021	Dec. 31, 2020
Oil [Member]		
Proved developed reserves (Barrel of Oil)	6,883	9,538
Proved undeveloped reserves (Barrel of Oil)	0	0
Natural Gas Liquids [Member]		
Proved developed reserves (Barrel of Oil)	2,914	3,187
Proved undeveloped reserves (Barrel of Oil)	0	0
Natural Gas [Member]		
Proved developed reserves (Barrel of Oil)	30,158	24,318
Proved undeveloped reserves (Barrel of Oil)	0	0
Oil Equivalents [Member]		
Proved developed reserves (Barrel of Oil)	14,823	16,778
Proved undeveloped reserves (Barrel of Oil)	0	0

Note 16 - Supplemental Oil and Gas Disclosures (Unaudited) - Future Net Cash Inflows (Details) - USD ($) $ in Thousands	Dec. 31, 2021	Dec. 31, 2020
Future cash inflows	$ 485,982	$ 345,869
Future production costs	(222,309)	(166,781)
Future development costs	(5,623)	(6,291)
Future income tax expense	0	0
Future net cash flows	258,050	172,797
Discount	(104,775)	(66,113)
Standardized Measure of discounted future net cash relating to proved reserves	$ 153,275	$ 106,684