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, 2023

or

☐ **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: 001-41546

Vitesse Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**88-3617511**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
9200 E. Mineral Avenue, Suite 200 Centennial, Colorado	**80112**
(Address of principal executive offices)	**(Zip Code)**

(720) 361-2500

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.01 per share	VTS	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the 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 whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒	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. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant on the last business day of the registrant's most recently completed second fiscal quarter (based on the closing sale price on such date) was approximately $558 million.

As of February 15, 2024, the registrant had 29,453,975 shares of common stock, $0.01 par value per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the registrant's 2024 Annual Meeting of Shareholders (the "Proxy Statement") are incorporated by reference into Part III of this report for the year ended December 31, 2023.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

The information in this Annual Report on Form 10-K contains statements which, to the extent they are not statements of historical or present fact, constitute "forward-looking statements" under the securities laws. These forward-looking statements are intended to provide management's current expectations or plans for our future operating and financial performance, based on assumptions currently believed to be valid. Forward-looking statements can be identified by the use of words such as "believe," "expect," "expectations," "plans," "strategy," "prospects," "estimate," "project," "target," "anticipate," "will," "should," "see," "guidance," "outlook," "confident" and other words of similar meaning in connection with a discussion of future operating or financial performance. Forward-looking statements may include, among other things, statements relating to future earnings, cash flow, results of operations, uses of cash, tax rates and other measures of financial performance or potential future plans, strategies or transactions of Vitesse, and other statements that are not historical facts. Forward-looking statements are not guarantees of future results and conditions, but rather are subject to numerous assumptions, risks, and uncertainties that may cause actual future results to be materially different from those contemplated, projected, estimated, or budgeted. Such assumptions, risks, uncertainties and other factors include, but are not limited to, the following:

- the timing and extent of changes in oil and natural gas prices;
- our ability to successfully implement our business plan;
- the pace of our operators' drilling and completion activity on our properties, including in connection with refrac programs and extended length three-mile lateral wells;
- our operators' ability to complete projects on time and on budget;
- uncertainties about estimates of reserves, identification of drilling locations and the ability to add reserves in the future;
- our ability to complete acquisitions;
- actions taken by third-party operators, processors, transporters and gatherers;
- natural disasters, adverse weather conditions, pandemic, war (such as the recent conflict in the Middle East and the ongoing military conflict in Ukraine), financial or political instability, casualty losses and other matters beyond our control;
- changes in general economic conditions, including central bank policy actions, bank failures and associated liquidity risks;
- our ability to achieve the benefits that we expect to achieve as an independent publicly traded company;
- the qualification of the Distribution and certain related transactions as tax-free under the Code;
- inflation;
- infrastructure constraints and related factors affecting our properties;
- competitive conditions in our industry;
- the effects of existing and future laws and governmental regulations;
- the availability and price of oil and natural gas to the consumer compared to the price of alternative and competing fuels;
- operating hazards and other risks incidental to gathering, storing and transporting oil and natural gas;
- restrictions in our Revolving Credit Facility;
- interest rates;
- the effects of ongoing or future litigation;
- cyber-related risks;
- changes in insurance markets impacting costs and the level and types of coverage available;
- financial, regulatory, and political risks associated with societal responses to climate change;
- extreme weather events and fluctuating regional and global weather conditions or patterns;
- energy efficiency and technology trends;
- changes in the availability and cost of capital;
- large customer defaults;
- labor relations; and
- changes in tax status.

The above list of factors is not exhaustive. For additional information on identifying factors that may cause actual results to vary materially from those stated in forward-looking statements, see the discussion under the section Part I, Item 1A. Risk Factors.

Reserve engineering is a process of estimating underground accumulations of hydrocarbons that cannot be measured in an exact way. The accuracy of any reserve estimates depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGLs that are ultimately recovered.

Any forward-looking statements, express or implied, included in this Annual Report on Form 10-K are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue. Any forward-looking statement that we make in this Annual Report on Form 10-K speaks only as of the date on which it was made. Except as otherwise required by applicable law, we expressly disclaim any obligation to, update or alter our forward-looking statements, whether as a result of new information, subsequent events or otherwise.

GLOSSARY

In this Annual Report on Form 10-K, unless the context otherwise requires:

- "3B Energy" refers to 3B Energy, LLC, the holder of a minority of the equity interests in Vitesse Energy prior to the Pre-Spin-Off Transactions and an entity owned by Bob Gerrity, our Chief Executive Officer and Chairman of our Board, and Brian Cree, our President;
- "Amended and Restated Bylaws" refers to the bylaws of Vitesse effective as of January 13, 2023;
- "Amended and Restated Certificate of Incorporation" refers to the certificate of incorporation of Vitesse effective as of January 12, 2023;
- "Basin" refers to a large natural depression on the earth's surface in which sediments generally brought by water accumulate;
- the "Board" refers to our board of directors;
- "Bbl" refers to one stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or NGLs;
- "BLM" refers to the Bureau of Land Management;
- "Boe" refers to barrels of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil;
- "Boe/d" refers to one Boe per day;
- "Btu" refers to a British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit;
- "CAA" refers to the Clean Air Act;
- "Cawley" refers to Cawley, Gillespie & Associates, Inc.;
- "CEQ" refers to the Council on Environmental Quality, a division of the Executive Office of the President;
- "CERCLA" refers to the Comprehensive Environmental, Response, Compensation, and Liability Act;
- "CFTC" refers to the Commodities Futures Trading Commission;
- "Code" refers to the United States Internal Revenue Code of 1986, as amended;
- "completion" refers to the process of preparing an oil and natural gas wellbore for production through the installation of permanent production equipment, as well as perforation and fracture stimulation to optimize production of oil, natural gas and/or NGLs;
- "condensate" refers to a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature;
- the "Corps" refers to the United States Army Corps of Engineers;
- "CWA" refers to the Federal Water Pollution Control Act of 1972;
- "DGCL" refers to the General Corporation Law of the State of Delaware;
- "differential" refers to an adjustment to the price of oil or natural gas from an established index price to reflect differences in the quality and/or location of oil or natural gas;
- the "Distribution" refers to the transaction on January 13, 2023 in which Jefferies distributed to its shareholders outstanding shares of our common stock held by Jefferies;
- the "Dodd-Frank Act" refers to the Dodd-Frank Wall Street Reform and Consumer Protection Act;
- the "DOI" refers to the Department of the Interior;
- "dry hole" refers to a well found to be incapable of producing oil and natural gas in sufficient quantities to justify completion;
- the "EPA" refers to the Environmental Protection Agency;
- the "ESA" refers to the Endangered Species Act;
- "ESG" refers to environmental, social and governance;
- "Exchange Act" refers to the Securities Exchange Act of 1934, as amended;
- "FDIC" refers to Federal Deposit Insurance Corporation
- "FERC" refers to the Federal Energy Regulatory Commission;
- "FTC" refers to the Federal Trade Commission;
- "GAAP" refers to accounting principles generally accepted in the United States;
- "Gerrity Bakken" refers to Gerrity Bakken, LLC, the holder of a minority of the equity interests in Vitesse Oil and an entity owned by Bob Gerrity, our Chief Executive Officer and a member of our Board;
- "GHGs" refer to greenhouse gases;
- "gross acres" refers to the total acres in which a working interest is owned;
- "gross wells" refers to the total wells in which a working interest is owned;
- "IPOs" refer to initial public offerings;
- the "IRA" refers to the Inflation Reduction Act of 2022;
- "IRS" refers to the Internal Revenue Service;

- "Jefferies" or "JFG" refers to Jefferies Financial Group Inc. and its consolidated subsidiaries other than, for all periods following the Spin-Off, Vitesse, unless the context requires otherwise;
- "Jefferies Capital Partners" refers to Jefferies Capital Partners V L.P. and Jefferies SBI USA Fund L.P., collectively, the holders of a majority of the equity interests in Vitesse Oil and entities in which Jefferies holds an indirect limited partner interest;
- "MBbls" refers to one thousand barrels of oil or NGLs;
- "MBoe" refers to one thousand barrels of oil equivalent;
- "Mcf" refers to one thousand cubic feet of natural gas;
- "MIUs" refers to management incentive units;
- "MMBoe" refers to one million barrels of oil equivalent;
- "MMBtu" refers to one million British thermal units;
- "MMcf" refers to one million cubic feet of natural gas;
- "net acres" refers to the sum of the fractional working interests owned in gross acres (e.g., a 10% working interest in a lease covering 1,280 gross acres is equivalent to 128 net acres);
- "net wells" refers to wells that are deemed to exist when the sum of fractional ownership working interests in gross wells equals one;
- "NAAQS" refers to National Ambient Air Quality Standards;
- "NEPA" refers to the National Environmental Policy Act;
- "NGLs" refer to natural gas liquids;
- "NSPS" refers to New Source Performance Standards;
- "NYMEX" refers to the New York Mercantile Exchange;
- "NYSE" refers to the New York Stock Exchange;
- "OPEC" refers to the Organization of Petroleum Exporting Countries;
- "OPA" refers to the Oil Pollution Act of 1990;
- "OTC" refers to the over-the-counter market;
- "PDP" or "proved developed producing" refers to proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods;
- "PDNP" or "proved developed non-producing" refers to proved reserves that are developed behind pipe and 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;
- "PHMSA" refers to the Pipeline and Hazardous Materials Safety Administration;
- "possible reserves" refers to the additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves;
- "Pre-Spin-Off Transactions" refers to the series of transactions, including Vitesse's acquisitions of Vitesse Energy and Vitesse Oil, consummated immediately prior to the Distribution;
- "Predecessor Company Agreement" means the Limited Liability Company Agreement of the Predecessor, dated as of July 1, 2018, as amended;
- "Prior Revolving Credit Facility" refers to Vitesse Energy's Amended and Restated Credit Agreement, dated as of April 29, 2022, as amended from time to time, among Vitesse Energy, as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto;
- "probable reserves" refers to the additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered;
- "productive well" refers to a well that is found to be capable of producing oil and natural gas in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes;
- "proved developed reserves" refers to proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of new equipment or operating methods is relatively minor compared to the cost of a new well;
- "proved reserves" refers to the quantities of oil and natural 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;
- "PUD" or "proved undeveloped" refers to proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. 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 from the date that such undrilled location was initially classified as proved undeveloped unless specific circumstances justify a longer time. Under no circumstances shall estimates of proved 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, or by other evidence using reliable technology establishing reasonable certainty:

- “RCRA” refers the Federal Resource Conservation and Recovery Act;
- “reserves” refers to estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project;
- “Revolving Credit Facility” refers to Vitesse’s Second Amended and Restated Credit Agreement, as amended from time to time, among Vitesse, as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto, dated as of January 13, 2023;
- “RSU” refers to Restricted Stock Units under the LTIP:
- “SDWA” refers to the Safe Drinking Water Act;
- “SEC” refers to the Securities and Exchange Commission;
- “Securities Act” refers to Securities Act of 1933, as amended;
- “SOFR” refers to the Secured Overnight Financing Rate;
- the “Spin-Off” refers to our separation on January 13, 2023 from Jefferies and the creation of an independent, publicly traded company, Vitesse, through (1) the Pre-Spin-Off Transactions and (2) the Distribution;
- “Standardized Measure” refers to discounted future net cash flows estimated by applying year-end SEC prices (based on the 12-month unweighted arithmetic average of the first-day-of-the-month oil and natural gas prices for such year-end period) to the estimated future production of year-end proved reserves. Future cash flows are reduced by estimated future production and development costs, including asset retirement obligations, based on year-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash flows over our tax basis in the oil and natural gas properties. Future net cash flows after income taxes are discounted using a 10% annual discount rate;
- “Stock Repurchase Program” refers to the stock repurchase program approved by the Board in February 2023 authorizing the repurchase of up to $60 million of the Company’s common stock;
- "SVB” refers to Silicon Valley Bank;
- “Tax Matters Agreement” refers to the tax matters agreement entered into between Jefferies and the Company on January 13, 2023;
- “Treasury Regulations” refers to final, temporary, and (to the extent they can be relied upon) proposed regulations promulgated under the Code, as amended from time to time (including corresponding provisions and succeeding provisions);
- “Two-stream basis” refers to the reporting of production or reserve volumes of oil and wet natural gas, where the NGLs have not been removed from the natural gas stream, and the economic value of the NGLs is included in the wellhead natural gas price;
- “Vitesse,” “we,” “our,” “us” and the “Company” (1) when used in regard to events prior to the Spin-Off, refer to Vitesse Energy and do not give effect to the consummation of the Pre-Spin-Off Transactions, and (2) when used in regard to events subsequent to the Spin-Off or future tense, refer to Vitesse Energy, Inc. and its consolidated subsidiaries and give effect to the consummation of the Pre-Spin-Off Transactions, in each case unless the context requires otherwise;
- “Vitesse Energy” and the “Predecessor” refer to Vitesse Energy, LLC and its consolidated subsidiaries;
- “Vitesse Energy Finance” refers to Vitesse Energy Finance LLC, the holder of a majority of the equity interests in Vitesse Energy prior to the Pre-Spin-Off Transactions and an indirect wholly owned subsidiary of Jefferies;
- “Vitesse Energy MIUs” refers to management incentive units with respect to Vitesse Energy;
- “Vitesse Oil” refers to Vitesse Oil, LLC;
- “Vitesse Oil Revolving Credit Facility” refers to Vitesse Oil’s Credit Agreement, dated as of July 23, 2015, as amended from time to time, among Vitesse Oil, as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto;
- “VOCs” refers to volatile organic compounds;
- “WOTUS” refers to the waters of the United States; and
- “WTI” refers to West Texas Intermediate.

PRESENTATION OF FINANCIAL AND OPERATING DATA

Unless otherwise indicated, the financial, reserve and operational information presented for periods prior to the January 13, 2023 Spin-Off in this Annual Report on Form 10-K is that of our Predecessor, Vitesse Energy. Also, unless otherwise indicated all references to wells, working interest, royalty interest, or acreage are based on the published information available as of the date indicated, which may not be current.

INDUSTRY AND MARKET DATA

This Annual Report on Form 10-K includes information concerning our industry and the markets in which we operate that is based on information from public filings, internal company sources, various third-party sources and management estimates. Management's estimates regarding Vitesse's position, share and industry size are derived from publicly available information and our internal research, and are based on assumptions we made upon reviewing such data and our knowledge of such industry and markets, which we believe to be reasonable. While we are not aware of any misstatements regarding any industry data presented in this Annual Report on Form 10-K and believe such data to be accurate, we have not independently verified any data obtained from third-party sources and cannot assure you of the accuracy or completeness of such data. Such data involve uncertainties and are subject to change based on various factors, including those discussed in "Part I, Item 1A, Risk Factors."

PART I

Items 1 and 2. Business and Properties

Overview

We are an independent energy company focused on returning capital to stockholders through owning interests as a non-operator in oil and natural gas wells. We engage in the acquisition, development and production of non-operated oil and natural gas properties in the United States that are generally operated by leading oil companies and are primarily in the Williston Basin of North Dakota and Montana. We also have properties in the Central Rockies, including the Denver-Julesburg Basin and the Powder River Basin. Since our inception, we have built a strong and diversified asset base through a combination of property acquisitions, development activities and the implementation of proprietary non-operating platforms and processes utilizing our extensive data resources. We believe the location and concentration of our assets in some of North America’s leading unconventional oil and natural gas resource plays, along with our technical and data capabilities, provide us with acquisition and development opportunities that will result in significant long-term value.

Vitesse has historically created value by acquiring non-operated minority working and mineral interests in oil and natural gas properties, comprising producing wells, near-term development opportunities and undeveloped acreage, and partnering with premier operators with significant experience in developing and producing oil and natural gas in our core areas. Over the past nine years, we have executed on our technical, data driven, and financially disciplined acquisition and development strategy to build our core position in the Williston Basin and Central Rockies and grow our oil and natural gas production. During that time, we have focused on limiting our downside by maintaining conservative acquisition guidelines, limiting our debt leverage and opportunistically hedging our oil production. As a result, we have been able to preserve value when many independent energy companies were forced into financial recapitalizations and restructurings when commodity prices collapsed in 2014, 2018 and 2020.

With the current oil and natural gas price environment, we are focused on using our cash flow to provide returns of capital to stockholders and maintain or grow our oil and natural gas production by developing our extensive inventory of drilling locations and acquiring both producing wells and new development opportunities, while maintaining a strong balance sheet.

We owned an average working interest of 2.7% in 5,734 gross (157.5 net) productive wells and royalty interests in an additional 1,140 productive wells as of December 31, 2023. We engage in oil and natural gas development by participating on a proportionate basis alongside third-party interests in wells drilled and completed in spacing units that include our acreage. As of December 31, 2023, we owned a working interest in 224 gross (6.7 net) wells that were being drilled or completed, and an additional 363 gross (9.9 net) wells that had been permitted for future development by our operating partners. We rely on our operators to propose, permit and initiate the drilling and completion of wells. We assess each drilling and completion opportunity on a case-by-case basis and participate in wells that are expected to meet a desired rate of return based upon estimates of recoverable oil and natural gas reserves, anticipated oil and natural gas prices, the expertise of the operator, and the anticipated completed well cost from each project, as well as other factors.

Our non-operated business model provides us with inherent flexibility regarding the cadence of capital deployment and the agility to allocate a portion of our cash flow to the drilling and completion opportunities that we believe will achieve the highest rate of return. We work with more than 35 experienced operators that provide technical insights and opportunities for additional acquisitions and continued development. In addition, our business model allows us to not be burdened with various contractual arrangements such as minimum drilling obligations, and we can avoid exploratory, upfront leasing and infrastructure costs customarily incurred by operators.

Our operators market and sell the oil and natural gas extracted from our wells. In addition, these operators coordinate the transportation of oil and natural gas production from wells in which we participate to appropriate pipelines or rail transport facilities pursuant to arrangements that such operators negotiate and maintain with various parties purchasing such production. The price at which our production is sold generally ties to a market spot price, and the differential between the market spot price and our realized sales price represents the embedded transportation and marketing costs of moving the oil and natural gas from the wellhead to the refinery or processing plant. The differential will fluctuate based on availability of pipeline, rail and other transportation methods.

The following table provides a summary of certain information regarding our assets as of December 31, 2023, including proved reserves as prepared by our third-party independent reserve engineers, Cawley.

	AS OF DECEMBER 31, 2023							
	NET ACRES(1)	PRODUCTIVE WELLS (1) GROSS	NET	AVERAGE DAILY PRODUCTION (2) (Boe/d)	PROVED RESERVES (3) (MBoe)	PV-10 (3) (in thousands)	% OIL	% PROVED DEVELOPED
Williston Basin	48,068	5,632	142	10,883	38,605	$ 645,256	69%	69%
Central Rockies (4)	205	102	16	1,006	1,990	36,814	52%	89%
Total/Weighted Average	48,273	5,734	158	11,889	40,595	$ 682,070	68%	70%

(1) In addition, we have royalty interests in 1,140 productive wells, on 1,402 net royalty acres.
(2) Represents the average daily production for the twelve months ended December 31, 2023.
(3) Proved reserve quantities and related PV-10 values have been derived from a WTI oil price of $78.21 per Bbl and Henry Hub natural gas price of $2.64 per MMBtu, which were calculated using an average of the first-day-of-the-month price for each month within the 12 months ended December 31, 2023 as required by SEC and FASB guidelines. PV-10 is a non-GAAP financial measure that does not include the effects of income taxes on future net revenues, and is not intended to represent fair market value of our oil and natural gas properties. For a definition of and reconciliation of PV-10 to its nearest GAAP financial measure, see Part II. Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations —Non-GAAP Financial Information.
(4) Includes Denver-Julesburg and Powder River Basin assets, consisting primarily of wellbore only ownership.

In addition to the proved reserves shown in the table above, we believe our acreage includes over 200 net undeveloped drilling locations not currently classified as proved as of December 31, 2023. We identify drilling locations based on our assessment of current geologic, engineering and land data. This includes current well spacing information per drilling and spacing unit derived from state agencies and our operators. We generally do not have evidence of our operators' long-term development plans, but we use a deterministic approach to define and allocate locations to proved, probable and possible reserves. While many of our undeveloped drilling locations qualify as geologic and engineering proved reserves, we limit our proved undeveloped reserves to those locations that are reasonably certain to be developed over the next five years.

The Spin-Off

On January 13, 2023, Jefferies completed the legal and structural separation of Vitesse Energy from Jefferies. To effect the separation, first, Jefferies, among others, undertook certain Pre-Spin-Off Transactions described below:

- Certain members of management of Vitesse Energy transferred all of their equity interest in Vitesse Energy to Jefferies as repayment for prior loans;
- Jefferies and other holders of Vitesse Energy's equity interests transferred all of their interest in Vitesse Energy to us in exchange for newly issued shares of our common stock;
- Vitesse Oil equity holders transferred their interests to us in exchange for newly issued shares of our common stock;
- Previous compensation agreements and compensation plans were eliminated and replaced with new compensation plans including the LTIP; and
- We entered into a Revolving Credit Facility, which amended and restated the Prior Credit Facility, and used the proceeds to repay in full and terminate the Vitesse Oil Revolving Credit Facility and repay the Prior Credit Facility.

Jefferies then distributed all of our outstanding common stock held by Jefferies to Jefferies' shareholders, and we became an independent, publicly traded company. After the Distribution, Jefferies does not own any shares of our common stock. In connection with the Spin-Off, we entered into certain agreements that governed, and will govern, our relationship with Jefferies, including a Separation and Distribution Agreement and a Tax Matters Agreement. Also, in connection with the Spin-Off, Vitesse Energy became a wholly owned subsidiary of a taxable entity (Vitesse). Therefore, we recorded the effects of income taxes within our consolidated financial statements which include the consolidated results of operations of Vitesse Energy and Vitesse Oil, as well as reflect the basis differences between tax and financial accounting for the assets and liabilities.

Business Strategy

Our business strategy is focused on creating long-term stockholder value through the acquisition, development and production of oil and natural gas assets at attractive rates of return, while maintaining a strong and conservative balance sheet and distributing a meaningful portion of our free cash flow to our stockholders. The key elements of our business strategy include the following:

- *Dividends to Stockholders*. Our business plan focuses on building a diversified, low-leverage, free cash flow generating business that can deliver meaningful dividends to our stockholders. We made cash distributions to our stockholders/members totaling $58.0 million, $36.0 million, and $12.0 million during the fiscal years ended December 31, 2023, December 31, 2022 and November 30, 2021, respectively, and $6.0 million during the month ended December 31, 2021.

- *Growth through Value-Enhancing Acquisitions*. We have been a consolidator and clearing house of non-operated working interests in various leading oil and natural gas shale plays in the United States, and we will continue that strategy and potentially pursue operated asset packages and other acquisition strategies going forward. Our near-term drilling acquisition strategy is centered around building a strong presence in our core basins by acquiring smaller non-operated lease and wellbore positions with direct exposure to near-term drilling activity. By virtue of their smaller footprint, these targeted acquisitions are generally completed at a significant discount to the prices paid for contiguous acreage positions typically sought by larger producers and operators of oil and natural gas wells. Acquisitions such as these have been a significant driver of increasing our production. Since inception we have closed approximately 170 discrete acquisitions totaling more than $570 million, and we intend to continue these activities, while at the same time evaluating and pursuing larger asset packages in both our current area of operations and other areas. We believe our disciplined acquisition strategy can responsibly add production, cash flow and scale to existing operations.
- *Built to Last*. From our inception, we have focused on creating a durable organization that generates strong financial returns and sustainable free cash flow through commodity cycles. Rather than primarily acquiring producing reserves, we have focused our efforts on acquiring an attractive inventory of undeveloped drilling locations that afford us flexibility in the face of oil and natural gas price fluctuations and taking advantage of technical improvements and cost reductions over time, supporting the sustainable generation of free cash flow. Our management team fosters a culture of innovation and continuous improvement, constantly looking for ways to improve our operations and technical and data analysis, and strengthen our organizational agility and adaptability.
- *Risk Diversification*. We seek to diversify our capital and operational risk through participation in a large number of oil and natural gas wells with multiple operators across multiple basins. We seek to diversify our risk by operator, formation, value concentration and commodity (oil and natural gas). As of December 31, 2023, we owned an average working interest of 2.7% in 5,734 gross (157.5 net) productive wells and royalty interests in an additional 1,140 productive wells, with more than 35 experienced operators that provide development and production activities on our oil and natural gas properties. We believe we can further diversify our risk over time with acquisitions in additional basins, focusing on accretive acquisitions of high-quality assets with experienced operators in the most prolific basins in the United States.
- *Strong Balance Sheet and Financial Flexibility*. We maintain financial strength and flexibility through the prudent management of our balance sheet and free cash flow. We maintain conservative indebtedness and a simple capital structure consisting of our Revolving Credit Facility and common stock. We intend to maintain the flexibility to manage our free cash flow by continuing to adhere to a target Net Debt to Adjusted EBITDA ratio (last twelve months) of less than 1.0.
- *Hedging Strategy*. To protect our ability to pay distributions, to fund capital investments and to reduce our exposure to the volatility of oil prices, we have historically entered into hedging derivative instruments for a portion of our expected oil production, which have included swaps, collars, puts and other structures. We have bought oil futures both on an opportunistic basis when WTI prices have allowed us to lock in attractive rates of return on our asset base and upon acquisitions of larger producing assets to protect returns. We have not hedged natural gas production since March 2022 due to the mismatch between our operators’ pricing formulas and settlement mechanics on natural gas hedges. Our current hedged position mitigates our exposure to volatile oil prices, with approximately 40% of our 2024 expected oil production hedged at an average price of $78.95 per Bbl. In the past, based on then-existing market conditions, we have hedged significantly higher percentages of our actual oil production. For further information see Part II. Item 7A. Quantitative and Qualitative Disclosure about Market Risk -”Commodity Price Risk.”
- *Responsible Stewards*. We are committed to ESG initiatives and seek a culture of improvement in ESG practices. We work to provide safe, reliable and affordable energy in a responsible manner by partnering with responsible operators in our core areas, while being cognizant of the broader energy transition. The key tenets of our ESG philosophy are to identify opportunities to reduce our environmental impact, improve safety, invest in our employees, and support the communities in which we live and work while improving transparency and accountability. Our Board is majority independent and composed of experienced professionals with a strong background in the energy industry and more broadly in business.

Our Competitive Strengths

We believe that we will be able to successfully execute our business strategies because of the following competitive strengths:

- *Every Decision is a Financial Decision.* Our business culture encourages employees to think like owners and to make decisions with a long-term perspective. We have developed a systematic approach of responsibly reviewing acquisition and development opportunities. As part of our efforts to maximize returns, we have established a capital allocation framework with the objective of allocating capital to acquisitions and development of oil and natural gas properties to drive sustainability and growth in free cash flow, the repayment of debt and payment of stockholder dividends. This framework entails disciplined investment in capital expenditures and acquisitions, allowing us to distribute a significant portion of our cash flow to our stockholders. We also retain flexibility with respect to share repurchases, subject to approval from our Board and as conditions warrant. We will continue to evaluate and pursue profitable and accretive acquisition and consolidation opportunities that enhance stockholder value and build scale. As opportunities arise, we intend to identify and acquire additional acreage and producing assets to supplement our existing operations.

- *Data and Technology Driven*. Our proprietary data-driven approach allows for rapid multi-disciplinary evaluation to determine the most attractive acquisition and development opportunities. We created customized data systems that are integrated, centralized and utilized by our employees so that decisions are based on a common base of information. We maintain real-time business intelligence dashboards to monitor operators, rigs, well performance, drilling and completion costs and production results. This data informs model forecasts, type curves and decisions about acquisition and development opportunities. We maintain responsive, basin-wide models that are updated in real time and incorporate historical data by operator and region. These models, along with our proprietary systems and platforms, provide necessary inputs and evaluation metrics, which allow us to make informed investment decisions based on forecasted production, operating expenses, type curves, drilling inventory, cash flow and other operational and financial outputs. As a result, we have the capability to process multiple opportunities quickly with the current team in place.
- *Experienced Management and Industry Relationships*. Vitesse's management team has developed deep and longstanding relationships with many of our operators, other working interest and mineral owners, investment banks, acquisition and divestiture companies and investors. A majority of our evaluated and executed acquisitions and transactions are self-sourced. We have become a preferred non-operator to some of the largest companies operating in the Williston Basin and Central Rockies given our track record of evaluating and acquiring non-operated oil and natural gas working interests, and being a responsible financial partner. As a result, we see broad deal flow from single wellbore near-term development acquisition opportunities to packages consisting of both producing and undeveloped assets worth hundreds of millions of dollars. Our management team has a track record of creating value at both private and public oil and natural gas companies.
- *Proactive Asset Management Philosophy*. Our experienced team of landmen and accountants review acquired assets to unlock incremental value. Many assets we acquire have title defects or other land related issues where deep analysis and consistent, quality diligence adds value in many areas, including increased working interest ownership and working capital management. Our long-term view provides the time to solve issues and find additional well interests to increase the velocity of overall returns. This is enabled by strong departmental relationships with operators and accurate data management.

Our Properties

Williston Basin (North Dakota and Montana)

The Williston Basin stretches from western North Dakota into eastern Montana, with the majority of drilling activity conducted by our operators located in Dunn, McKenzie, Mountrail, and Williams Counties, North Dakota. Approximately 76% of our 48,068 net acres as of December 31, 2023 are in the above counties and target the Bakken and Three Forks formations. Approximately 99% of our acreage in the Williston Basin is held by production. As of December 31, 2023, we had a working interest in 5,632 gross (141.7 net) productive wells and royalty interests in an additional 1,140 productive wells. In addition to these productive wells, we had 206 gross (4.5 net) working interest wells that were being drilled or completed, and 359 gross (9.8 net) wells that have been permitted for future development by our operating partners. Our estimated proved reserves in North Dakota and Montana as of December 31, 2023 were 38,605 MBoe (69% oil), which represented 95% of our total estimated proved reserves and contributed average production of 10,883 Boe per day for the year ended December 31, 2023.

We have been active in the Williston Basin since 2014 and have seen our thesis for continued growth and expansion of the field come to fruition. The Williston Basin is a world class oil field and we expect to see continued growth in recoverable reserves for many years. We have a significant inventory of remaining undeveloped drilling locations that we expect to see developed over the next 15 to 25 years. In addition, we are seeing incremental growth and development throughout the field utilizing newer technologies including refrac programs and extended length three-mile lateral wells.

Central Rockies (Colorado and Wyoming)

The Denver-Julesburg Basin is located in Northeast Colorado and Southeast Wyoming, with the majority of operator horizontal drilling activity located in Weld and Broomfield Counties, Colorado, and Laramie County, Wyoming. Our assets in this area primarily consist of wellbore only ownership and target the Codell formation and several productive zones within the Niobrara formation. We owned a working interest in 96 gross (14.8 net) productive wells as of December 31, 2023 operated primarily by Civitas Resources, Inc., EOG Resources Inc. and Chevron Corporation. In addition to the productive wells, we have 18 gross (2.2 net) wells that were being completed by our operating partners as of December 31, 2023.

Our Powder River Basin assets primarily target the Parkman, Sussex, Turner and Niobrara formations. We owned a working interest in 6 gross (1.0 net) productive wells as of December 31, 2023. In addition to these productive wells, we have 3 gross (0.1 net) wells that have been permitted for future drilling by our operators as of December 31, 2023.

Reserves

Estimated Net Proved Reserves

The table below summarizes our estimated net proved reserves for the periods indicated based on reports prepared by Cawley, our third-party independent reserve engineer, except as otherwise described herein. In preparing its reports, Cawley evaluated properties representing our total proved reserves as of December 31, 2023, December 31, 2022 and November 30, 2021 in accordance with the rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities. Reserves as of December 31, 2021 represent our reserves as of November 30, 2021, which are based on a report prepared by Cawley, as adjusted for reserve activity during the one month period of December 1, 2021 to December 31, 2021, which reflect internal reserve estimates. Our estimated net proved reserves in the table below do not include probable or possible reserves and do not in any way include or reflect our commodity derivatives.

	AS OF DECEMBER 31,			AS OF NOVEMBER 30,
	2023	2022	2021	2021
Estimated proved developed:				
Oil (MBbls)	18,440	17,290	17,612	17,764
Natural gas (MMcf)	60,202	58,897	58,058	58,437
Total (MBoe)	28,474	27,106	27,289	27,504
Estimated proved undeveloped:				
Oil (MBbls)	9,303	13,155	11,785	11,765
Natural gas (MMcf)	16,907	21,217	19,623	19,586
Total (MBoe)	12,121	16,691	15,055	15,030
Estimated total proved reserves:				
Oil (MBbls)	27,743	30,445	29,397	29,529
Natural gas (MMcf)	77,109	80,114	77,681	78,023
Total (MBoe)	40,595	43,797	42,344	42,534
Percent proved developed	70.1%	61.9%	64.4%	64.7%

Estimated net proved reserves as of December 31, 2023 were 40,595 MBoe, and we held working interests in 25.4 net proved undeveloped drilling locations included in such reserves as of December 31, 2023.

The table below sets forth summary information by reserve category with respect to estimated proved reserves volumes and related PV-10 values as of December 31, 2023.

	SEC PRICING PROVED RESERVES [(1)]					
	RESERVES VOLUMES				PV-10 [(3)]	
RESERVE CATEGORY	OIL (MBbls)	NATURAL GAS (MMcf)	TOTAL (MBoe) [(2)]	%	AMOUNT (in thousands)	%
PDP Properties	17,981	58,911	27,799	68%	$ 521,494	77%
PDNP Properties	459	1,292	675	2%	15,108	2%
PUD Properties	9,303	16,907	12,121	30%	145,468	21%
Total	27,743	77,110	40,595	100%	$ 682,070	100%

(1) Oil and natural gas reserve quantities and related discounted future net cash flows are valued as of December 31, 2023 and are derived from a WTI price of $78.21 per Bbl and Henry Hub natural gas price of $2.64 per MMBtu. Under SEC guidelines, these prices represent the average prices per Bbl of oil and per MMBtu of natural gas at the beginning of each month in the twelve-month period prior to the end of the reporting period.

(2) MBoe are computed based on a conversion ratio of one Boe for each barrel of oil and one Boe for every 6 Mcf of natural gas.

(3) PV-10 is a non-GAAP financial measure that does not include the effects of income taxes on future net revenues, and is not intended to represent fair market value of our oil and natural gas properties. For a definition of and reconciliation of PV-10 to its nearest GAAP financial measure, see Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Non-GAAP Financial Information."

Estimated Net Proved Undeveloped Reserves

As of December 31, 2023, we had approximately 12,121 MBoe of estimated net proved undeveloped reserves. Changes in estimated net proved undeveloped reserves that occurred from December 31, 2022 to December 31, 2023 were due to:

	MBoe
Balance at December 31, 2022	16,691
Acquisitions	289
Extensions, discoveries and other additions	2,592
Transfers to estimated proved developed reserves	(2,491)
Revisions	(4,960)
Balance at December 31, 2023	12,121

Notable changes in proved undeveloped reserves for the year ended December 31, 2023 included the following:

- *Acquisitions:* We acquired 289 MBoe of proved undeveloped reserves in the Williston Basin and Central Rockies during 2023.
- *Extensions, discoveries and other additions:* During 2023, extensions and discoveries associated almost entirely with proved undeveloped locations in the Williston Basin added 2,592 MBoe of proved undeveloped reserves.
- *Transfers to estimated proved developed reserves*: Development costs of approximately $41 million were incurred in connection with the conversion of approximately five net undeveloped locations classified as proved at December 31, 2022, and 2,491 MBoe of proved undeveloped reserves were transferred to proved developed reserves during 2023. In addition to the conversion and transfer of proved reserves, although not included in the table above, 1,478 MBoe of reserves from three net undeveloped locations not classified as proved undeveloped at December 31, 2022 were transferred to proved developed reserves during the period.
- *Revisions*: In 2023, revisions to previous estimates decreased proved undeveloped reserves by a net amount of 4,960 MBoe. These revisions were primarily attributable to the reclassification of undeveloped drilling locations totaling 4,184 MBoe of proved reserves from proved to non-proved and were made proactively as a result of lower-than-expected rig activity in the Williston Basin during the year and continued compliance with the SEC 5-year development rule. In addition, the revisions included decreases in proved undeveloped reserves of 541 MBoe related to forecast/timing/interest changes and 235 MBoe associated with lower commodity prices and slightly higher lease operating expenses due to increased workover activity.

We expect that our proved undeveloped reserves will continue to be converted to proved developed producing reserves as additional wells are drilled on our acreage. We also expect that some component of our undeveloped drilling locations not classified as proved at December 31, 2023 will be converted to proved developed producing reserves. All locations comprising our remaining proved undeveloped reserves are forecast to be drilled within five years from initially being recorded in accordance with our development plan.

As of December 31, 2023, the PV-10 value of our proved undeveloped reserves amounted to approximately 21% of the PV-10 value of our total proved reserves. There are numerous uncertainties regarding undeveloped reserves. The development of these reserves is dependent upon a number of factors which include but are not limited to: financial targets such as drilling within cash flow or reducing debt, satisfactory rates of return on proposed drilling projects, and the level of drilling activity by operators in areas where we hold leasehold interests. With 77% of the PV-10 value of our total proved reserves supported by producing wells, we believe we will have sufficient cash flows and adequate liquidity to execute our development plan. PV-10 is a non-GAAP financial measure that does not include the effects of income taxes on future net revenues and is not intended to represent the fair market value of our oil and natural gas properties. For a definition of and reconciliation of PV-10 to its nearest GAAP financial measure, see Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - "Non-GAAP Financial Information."

Independent Petroleum Engineers

We have engaged Cawley to prepare our estimated proved reserves. Cawley is an independent reservoir-evaluation consulting firm who evaluates oil and natural gas properties and independently certifies petroleum reserves quantities for various clients throughout the United States. Cawley has substantial experience calculating the reserves of various other companies with operations targeting the Bakken and Three Forks formations and, as such, we believe Cawley has sufficient experience to appropriately determine our reserves. Cawley utilizes proprietary technology, systems and data to calculate our reserves commensurate with this experience. The reports of our estimated proved reserves in their entirety are based on the information we provide to them. Cawley is a Texas Registered Engineering Firm (F-693). The technical person at Cawley who is primarily responsible for overseeing the preparation of our reserves estimates is Todd Brooker, President. Mr. Brooker is a state of Texas

Licensed Professional Engineer (License # 83462). He is also a member of the Society of Petroleum Engineers and has over 25 years of experience in oil and natural gas reservoir studies and evaluations.

In accordance with applicable requirements of the SEC, estimates of our net proved reserves and future net revenues are made using average prices at the beginning of each month in the 12-month period prior to the date of such reserve estimates and are held constant throughout the life of the properties.

The reserves set forth in the Cawley report for our properties are estimated by performance methods or analogy. In general, reserves attributable to producing wells and/or reservoirs are estimated by performance methods such as decline curve analysis which utilizes extrapolations of historical production data. Reserves attributable to non-producing and undeveloped reserves included in our report are estimated by analogy.

To estimate economically recoverable oil and natural gas reserves and related future net cash flows, Cawley considers many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be demonstrated to be economically producible based on existing economic conditions including the prices and costs at which economic productivity from a reservoir is to be determined as of the effective date of the report. With respect to the property interests we own, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, production taxes, recompletion and development costs and product prices are based on the SEC regulations, geological maps, well logs, core analyses, and pressure measurements.

The reserve data set forth in the Cawley report represents only estimates, and should not be construed as being exact quantities. They may or may not be actually recovered, and if recovered, the actual revenues and costs could be more or less than the estimated amounts. Moreover, estimates of reserves may increase or decrease as a result of future operations.

Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. There are numerous uncertainties inherent in estimating oil and natural gas reserves and their estimated values, including many factors beyond our control. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geologic interpretation and judgment. As a result, estimates of different engineers, including those used by us, may vary. In addition, estimates of reserves are subject to revision based upon actual production, results of future development and exploration activities, prevailing oil and natural gas prices, operating costs and other factors. The revisions may be material. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered and are highly dependent upon the accuracy of the assumptions upon which they are based. See “Part I. Item IA. Risk Factors—Risks Relating to our Business—Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our total reserves.”

Internal Controls Over Reserves Estimation Process

We utilize Cawley, a third-party reservoir engineering firm, as our independent reserves evaluator for 100% of our proved reserves base. In addition, we employ an internal engineering department, with the reserves process led by our Senior Reserves Engineer, who is responsible for overseeing the preparation of our reserves estimates. Our Senior Reserves Engineer has a B.S. in Chemical Engineering from the University of Tulsa, over twenty years of oil and gas experience, including 15 years with a focus on reserve evaluation, and additional experience with operations and production engineering in multiple basins.

Our reserve engineering department meets with our independent third-party engineering firm to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data, as well as management review, such as, but not limited to the following:

- comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input;
- review of working interests and net revenue interests in our reserves database against our well ownership system;
- review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;
- review of updated capital costs based on information from our operators and actual drilling and completion costs on recent activity;
- review of internal reserve estimates by well and by area by our internal reservoir engineer;
- discussion of material reserve variances among our internal reservoir engineer and our executive management; and
- review of a preliminary copy of the reserve report by executive management.

Production, Price and Production Expenses

We report our oil and natural gas production on a Two-stream basis. The price that we receive for the oil and natural gas produced from wells in which we hold interests is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Oil supply in the United States has grown over the past few years, and the supply of oil could impact oil prices in the United States if the supply outstrips domestic demand. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The table below sets forth information regarding our oil and natural gas production, realized prices and production costs for the periods indicated. For additional information on price calculations, see the information in "Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	FOR THE YEARS ENDED DECEMBER 31,		FOR THE MONTH ENDED DECEMBER 31,	FOR THE YEAR ENDED NOVEMBER 30,
	2023	2022	2021	2021
Net Production:				
Oil (MBbls)	2,968	2,575	220	2,436
Natural gas (MMcf)	8,232	7,274	582	7,065
Total (MBoe)	4,340	3,787	317	3,613
Oil (Bbl) per day	8,130	7,054	7,107	6,673
Natural gas (Mcf) per day	22,553	19,929	18,774	19,357
Total (Boe) per day	11,889	10,376	10,236	9,899
Average Sales Prices:				
Oil (per Bbl)	$ 73.59	$ 90.73	$ 67.16	$ 59.46
Effect of gain (loss) on realized oil derivative on average price (per Bbl)	0.40	(18.07)	(7.65)	(5.37)
Oil net of realized oil derivatives (per Bbl)	$ 73.99	$ 72.66	$ 59.51	$ 54.09
Natural gas and NGLs (per Mcf)	$ 1.88	$ 6.64	$ 2.87	$ 3.26
Effect of gain (loss) on realized natural gas derivatives on average price (per Mcf)	—	(0.08)	0.02	(0.12)
Natural gas and NGLs net of realized natural gas derivative (per Mcf)	$ 1.88	$ 6.56	$ 2.89	$ 3.14
Realized price on a Boe basis excluding realized commodity derivatives	$ 53.90	$ 74.43	$ 51.89	$ 46.45
Effect of gain (loss) on realized commodity derivatives on average prices (per Boe)	0.27	(12.44)	(5.28)	(3.85)
Realized price on a Boe basis net of realized commodity derivatives	$ 54.17	$ 61.99	$ 46.61	$ 42.60
Average Costs:				
Lease operating expense (per Boe)	$ 9.11	$ 8.22	$ 7.16	$ 7.35
Production taxes (per Boe)	$ 4.98	$ 6.36	$ 4.22	$ 4.02

Drilling and Development Activity

The table below sets forth the number of gross and net productive and non-productive wells in which we owned a working interest drilled in the periods indicated. The number of wells drilled refers to the number of wells completed at any time during the period, regardless of when drilling was initiated.

	YEAR ENDED DECEMBER 31,				MONTH ENDED DECEMBER 31,		YEAR ENDED NOVEMBER 30,	
	2023		2022		2021		2021	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Exploratory Wells:								
Productive Oil	—	—	—	—	—	—	—	—
Productive Natural gas	—	—	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—
Development Wells:								
Productive Oil [(1)]	414	9.78	295	7.53	28	0.97	243	6.55
Productive Natural gas	—	—	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—	—	—
	414	9.78	295	7.53	28	0.97	243	6.55
Total productive exploratory and development wells [(1)]	414	9.78	295	7.53	28	0.97	243	6.55

(1) Includes royalty interests in 83 gross (0.12 net) wells drilled in the year ended December 31, 2023, 45 gross (0.09 net) wells drilled in the year ended December 31, 2022, 0 gross (0.00 net) wells drilled in the month ended December 31, 2021 and 57 gross (0.08 net) wells drilled in the year ended November 30, 2021.

The tables below set forth summary information by location with respect to estimated productive wells in which we owned a working interest or a royalty interest, as applicable as of December 31, 2023.

	AS OF DECEMBER 31, 2023		
	PRODUCTIVE WORKING INTEREST OIL WELLS		AVERAGE WORKING INTEREST
	GROSS	NET	
Combined Total:			
Williston Basin	5,632	142	2.5%
Central Rockies [(1)]	102	16	15.5%
Total	5,734	158	2.7%

	AS OF DECEMBER 31, 2023		
	PRODUCTIVE ROYALTY INTEREST OIL WELLS		AVERAGE ROYALTY INTEREST
	GROSS	NET	
Combined Total:			
Williston Basin	1,140	3	0.2%
Central Rockies [(1)]	—	—	—%
Total	1,140	3	0.2%

(1) Includes Denver-Julesburg and Powder River Basin wells.

As of December 31, 2023, we owned a working interest in 224 gross (6.7 net) wells that were being drilled or completed, and an additional 363 gross (9.9 net) wells that had been permitted for development by our operating partners and a net revenue interest in 0.1 net wells that are being drilled or completed and 0.3 net wells permitted for development.

Acreage

The table below sets forth our estimated gross and net developed and undeveloped acreage by geographic area as of December 31, 2023.

	DEVELOPED ACREAGE		UNDEVELOPED ACREAGE		TOTAL ACREAGE		ROYALTY ACRES	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Williston Basin	1,623,690	45,678	59,521	2,390	1,683,211	48,068	124,558	1,401
Central Rockies [(1)]	3,070	113	11,520	92	14,590	205	640	1
Total	1,626,760	45,791	71,041	2,482	1,697,801	48,273	125,198	1,402

(1) Includes Denver-Julesburg and Powder River Basin acreage.

Approximately 99% of our undeveloped acreage is held by production as of December 31, 2023, with 640 gross (5 net) acres subject to potential expiration in 2025.

Industry Operating Environment

We operate in a highly cyclical industry. Demand for oil and natural gas is cyclical and is subject to large and rapid fluctuations. This is primarily because the industry is driven by commodity demand and corresponding price increases. When oil and natural gas price increases occur, producers generally increase their capital expenditures, which generally results in greater revenues and profits. The increased capital expenditures also ultimately result in greater production, which historically has resulted in increased supplies and reduced prices. For these reasons, our results of operations may fluctuate from quarter-to-quarter and from year-to-year, and these fluctuations may distort period-to-period comparisons of our results of operations.

The global energy mix is also transitioning to less carbon-intensive sources and our business is not immune to these trends. In our view, energy transition will play out over the coming decades and oil and natural gas will still be a dominant source for affordable and reliable energy. We see the quality of our asset base, depth of inventory and competitive economics carrying us profitably through this transition.

Development

We primarily engage in oil and natural gas development and production by participating on a proportionate basis alongside third-party interests in wells drilled and completed in spacing units that include our leasehold interests. In addition, we acquire wellbore interests in wells in which we do not hold the underlying leasehold interests from third parties unable or unwilling to participate in certain well proposals. We typically depend on our operators to propose, permit, and initiate the drilling and completion of wells. Prior to commencing drilling, our operators are required to provide all owners of working interests within the designated spacing unit the opportunity to participate in the drilling and completion costs and net revenues of the well to the extent of their pro-rata share of such interest within the spacing unit. We assess each drilling and completion opportunity on a case-by-case basis and participate in wells that are expected to meet a desired return based upon estimates of recoverable oil and natural gas, anticipated oil and natural gas prices, the expertise of the operator, and the anticipated completed well cost from each project, as well as other factors. Historically, we have participated pursuant to our working interest in a vast majority of the wells proposed to us. However, declines in oil prices typically reduce both the number of well proposals we receive and the proportion of well proposals in which we elect to participate. Our land, engineering and finance teams use our extensive database to make these economic decisions. Vitesse created customized data systems that are integrated, centralized and utilized by our employees to evaluate development opportunities. These data systems maintain real time dashboards to monitor operators, rigs, well performance and costs. Given our large acreage footprint and substantial number of well participations, we believe we can make accurate economic drilling and completion decisions utilizing our data systems.

Historically, we have not managed our commodities marketing activities internally. Instead, our operators market and sell oil and natural gas produced from wells in which we have an interest. Our operators coordinate the transportation of our oil and natural gas production from our wells to appropriate pipelines or rail transport facilities pursuant to arrangements that they negotiate and maintain with various parties purchasing the production. We understand that our operating partners generally sell our production to a variety of purchasers at prevailing market prices under separately negotiated short-term contracts. Although we have historically relied on our operators for these activities, we may in the future seek to take a portion of our production in kind and internally manage the marketing activities for such production; however, this would be costly and inefficient based on our current average working interest ownership. The price at which our production is sold is generally tied to the spot market for oil or natural gas. The price at which our oil production is sold typically reflects a discount to the WTI benchmark price. This differential primarily represents the transportation costs in moving the oil from wellhead to refinery and will fluctuate based on availability of pipeline, rail and other transportation methods. The price at which our natural gas production is sold may reflect either a discount or premium to the NYMEX benchmark price.

Competition

Although we plan to focus on a target asset class and deal size where we believe that competition and costs are reduced as compared to the broader oil and natural gas industry, the acquisition market for non-operated and operated properties remains intensely competitive, and we will compete with other oil and natural gas companies for acquisitions, some of which have substantially greater resources than us and may be able to pay more for properties.

Finally, the emerging impact of climate change activism, fuel conservation measures, governmental requirements for renewable energy resources, increasing demand for alternative forms of energy, and technological advances in energy generation devices may result in reduced demand for the oil and natural gas we produce.

Title to Our Properties

Prior to completing an acquisition of non-operated working or royalty interests, we perform a title review on each tract to be acquired. Our title review is meant to confirm the quantum of non-operated working and royalty interest owned by a prospective seller, the property's lease status and royalty amount as well as encumbrances or other related burdens.

In addition to our initial title work, operators often will conduct a thorough title examination prior to drilling a well. Should our title work uncover any further title defects, we will perform curative work with respect to such defects. We believe that the title to our assets is satisfactory in all material respects.

Our oil and natural gas properties are subject to customary royalty and other interests, liens under indebtedness, liens incident to operating agreements, liens for taxes and other burdens, including other mineral encumbrances and restrictions. Indebtedness under our Revolving Credit Facility is secured by liens on substantially all our assets. We do not believe that any of these burdens materially interfere with the use of our properties or the operation of our business.

Seasonality

Winter weather events and conditions, such as ice storms, blizzards and freezing conditions, and lease stipulations can limit or temporarily halt the drilling and producing activities of our operators and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt the operations of our operators and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operators' operations.

Regulation and Environmental Matters

Our operations are subject to various rules, regulations and limitations impacting the oil and natural gas acquisition, development and production industry as a whole.

Regulation of Oil and Natural Gas Production

Our oil and natural gas development, production and related operations are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, North Dakota and Montana require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the development and production of oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, limitations or prohibitions on the venting or flaring of natural gas, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. Moreover, the federal government and its agencies have from time to time, imposed or considered imposing new or more stringent rules or policies that impact oil and gas exploration and production operations, including pausing or withholding acreage from lease sales and increasing royalty rates on federal lands, restricting national oil and gas exports and related infrastructure, and regulating or taxing emissions from production facilities. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, FERC, EPA and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of Transportation of Oil

Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. 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 pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost-of-service filing. Every five years, FERC reviews the appropriateness of the index level in relation to changes in industry costs. On January 20, 2022, FERC established a new price index for the five-year period which commenced on July 1, 2021.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future.

Onshore gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities is done on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation is generally toward stricter standards, and this trend will likely continue. These laws and regulations may:

- require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;
- limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their rules and regulations, and violations can be subject to fines, injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations, and have no known material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general.

CERCLA, and comparable state statutes impose strict, joint and several liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of “hazardous substances” found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. RCRA, and comparable state statutes, govern the disposal of “solid waste” and “hazardous waste” and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of “hazardous substance,” state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although the RCRA classifies certain oil field wastes as “non-hazardous,” such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. Concern over induced seismicity resulting from the injection of oil field wastes has increased regulatory scrutiny of and local opposition to disposal well operations in certain areas of the United States, though primarily not in the regions in which our interests are located.

The ESA seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under the ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize a covered species or its habitat. The ESA provides for criminal penalties for willful violations of the ESA. Other statutes that provide protection to animal and plant species and that may apply to our operators’ activities include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operators are in compliance with such statutes, any change in these statutes or any reclassification of a species as endangered or threatened could subject our company (directly or indirectly through our operators) to significant expenses to modify our operations or could force discontinuation of certain operations altogether.

The CAA controls air emissions from oil and natural gas production and natural gas processing operations, among other sources. EPA regulations under the CAA include NSPS for the oil and natural gas source category to address emissions of pollutants, including sulfur dioxide, methane and VOCs, NAAQS for certain ambient levels of criteria pollutants and a separate set of, including ground-level ozone, and emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities., among other monitoring, reporting, and permitting regulations. In recent years there has been considerable focus on the regulation of methane emissions from the oil and gas sector. The EPA proposed and finalized more stringent methane rules for new, modified, and reconstructed upstream and midstream facilities under New Source Performance Standards (“NSPS”) Subpart OOOOb, as well as, for the first time ever, standards for existing sources under NSPS Subpart OOOOc in December 2023. The final rules expand the scope of regulated oil and gas sources beyond those currently regulated under the existing NSPS Subpart OOOOa. Under the final rules, states have two years to prepare and submit plans to impose methane and VOC emission controls for existing sources. The presumptive standards established under the final rules are generally same for both new and existing sources and include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring technologies, the reduction of emissions by 95% through capture and control system, zero-emission requirements for specific components and equipment, so-called green well completion requirements, and the establishment of a “super emitter” response program which would allow certified third parties to report large emission events to EPA, triggering additional investigation, reporting, and repair obligations, among other more stringent operational and maintenance requirements. Fines and penalties for violations of these rules could be substantial. These newly adopted final rules are likely to face immediate legal challenges. Separately, the BLM has also proposed rules to limit venting, flaring, and methane leaks for oil and gas operations on federal lands. These requirements and any future regulatory developments have the potential to increasing operating costs for production activities on our properties and thus may adversely affect our financial results. We also note that the regulatory activities discussed above are subject to ongoing intense political debate and could be subject to major modification depending on the outcome of the 2024 election cycle.

These regulations and proposals and any other new regulations requiring the installation of more sophisticated pollution control equipment or restrictions on operations could have a material adverse impact on our business, results of operations and financial condition.

The CWA imposes restrictions and controls on the discharge of produced waters and other pollutants into WOTUS. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The meaning of WOTUS has been heavily litigated and the subject of multiple rulemakings in recent years. In May 2023 the U.S. Supreme Court released its opinion in Sackett v. EPA, which involved issues relating to the legal tests used to determine whether wetlands qualify as WOTUS. The Sackett decision invalidated certain parts of the then-current WOTUS rule and significantly narrowed its scope, resulting in a revised rule being issued by EPA and the Corps in September 2023. However, implementation of the September 2023 rule currently varies by state due to ongoing litigation. In 27 states party to the litigation, agencies are interpreting the definition of WOTUS consistent with the pre-2015 regulatory regime and the changes made by the Sackett decision. Regardless, the applicable WOTUS definition affects what CWA permitting or other regulatory obligations may be triggered during development and operation of our properties, and changes to the WOTUS definition could cause delays in development and/or increase the cost of development and operation of our properties. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The OPA amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. As such, a violation of the OPA has the potential to adversely affect our business.

The CAA, CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.

The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the SDWA. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Substantially all of the oil and natural gas production in which we have interest is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into a wellbore to create cracks in the deep-rock formation to stimulate gas production. Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. Congress continues to consider legislation to amend the SDWA to address hydraulic fracturing operations. In addition, in 2020, the Supreme Court held that the CWA requires a discharge permit if the addition of pollutants through groundwater is the "functional equivalent" of a direct discharge from the point source into navigable waters. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. If in the future CWA permitting is required for saltwater injection wells as a result of the 2020 Supreme Court ruling, the costs of permitting and compliance for injection well operations by the companies that operate the Properties could increase.

Scrutiny of hydraulic fracturing activities continues in other ways. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. Several states, including Montana and North Dakota where our properties are located, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado, have enacted bans on hydraulic fracturing. In Colorado, the Colorado Supreme Court has ruled the municipal bans were preempted by state law. However, the Colorado legislature subsequently enacted "SB 101" that gave significant local control over oil and natural gas wellhead operations. Municipalities in Colorado have enacted local rules restricting oil and natural gas operations based on SB 101. We cannot predict whether any other legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, it could lead to delays, increased operating costs and process prohibitions that would materially adversely affect our revenue and results of operations. For more information on risks related to hydraulic fracturing see Part I. Item 1A. Risk Factors—Risks Relating to Legal and Regulatory Matters—Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

The NEPA establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA. Many of the activities of our third-party operators are covered under NEPA. Some activities are subject to robust NEPA review which could lead to delays and increased costs that could materially adversely affect our revenues and results of operations. Other activities are covered under categorical exclusions which results in a shorter NEPA review process. In April 2022, the Biden Administration finalized a rule to undo certain changes to NEPA enacted under the Trump Administration. The 2022 Rule requires NEPA reviews to incorporate consideration of indirect and cumulative impacts of the proposed project, including effects on climate change and GHGs, consistent with pre-2020 requirements. The new rule also allows agencies to create stricter NEPA rules as they see fit but left in place the Trump Administration's two-year time limit to complete environmental impact statements. Then, in January 2023, the CEQ released updated guidance for federal agency consideration of GHG emissions and climate change impacts in environmental assessments, which includes, among other recommendations, best practices for analyzing and communicating climate change effects. Additionally, in July 2023 the CEQ proposed revisions to the NEPA implementing regulations that would expand requirements to analyze the cumulative effects of the project on climate change and consider any disproportionate impact of the project on communities with environmental justice concerns as well enhance certain project obligations for implementing environmental mitigation measures.

Climate Change

Significant studies and research have been devoted to climate change, and climate change has developed into a major political issue in the United States and globally. Certain research suggests that greenhouse gas emissions contribute to climate change and pose a threat to the environment. Recent scientific research and political debate has focused in part on carbon dioxide and methane incidental to oil and natural gas exploration and production.

In response to findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, require preconstruction and operating permits for GHG emissions from certain large stationary sources that already emit conventional pollutants above a certain threshold. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis (the regulations for which are currently undergoing revision to support implementation of the IRA’s methane emissions fee provision), which may include operations on our properties.

Congress has from time to time considered legislation to monitor, limit, or reduce emissions of GHGs, but to date has not passed comprehensive climate legislation. However energy legislation and other regulatory initiatives have been and continue to be proposed that are relevant to climate change and GHG emissions issues. For example, in August 2022, Congress passed, and President Biden signed, the IRA, which establishes a program designed to reduce methane emissions from certain oil and natural gas facilities, which includes a charge on methane emissions above certain thresholds. In addition, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The Biden Administration has also committed to incorporating climate change considerations into executive agency decision-making and has published a number of executive orders related to climate change. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact us, any future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, operators’ equipment and operations could require them to incur costs to reduce emissions of GHGs associated with their operations. For example, substantial limitations on GHG emissions could adversely affect demand for the oil and gas produced from our properties. For a more detailed discussion of the risks associated with climate change legislation or regulation, see Part I. Item 1A Risk Factors Risks Relating to Legal and Regulatory Matters—The adoption of climate change legislation or regulations restricting emissions of carbon dioxide, methane, and other greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.”

In addition, spurred by increasing concerns regarding climate change, the oil and natural gas industry faces growing demand for corporate transparency and a demonstrated commitment to sustainability goals. The industry could also be impacted by governmental initiatives aimed at encouraging fuel conservation and shifts in capital investment to alternative energy sources. For more information, see Part I. Item 1A. Risk Factors, Risks Relating to our Business—Increased attention to ESG matters, including climate change, may impact our business and access to capital and - Decarbonization measures and related governmental initiatives, technological advances, increased competitiveness of alternative energy sources and negative shift in market perception towards the oil and natural gas industry could reduce demand for oil and natural gas.

Finally, climate changes may have significant physical effects, such as increased frequency and severity of storms, freezes, floods, drought, hurricanes and other climatic events; if any of these effects were to occur, they could have an adverse effect on the operations of our operating partners, and ultimately, our business.

Human Capital Management

As of December 31, 2023, we had 36 full time employees. We may hire additional personnel as appropriate. We also may use the services of independent consultants and contractors to perform various professional services. We are focused on attracting, engaging, developing, retaining and rewarding top talent. We strive to enhance the economic and social well-being of our employees. We are committed to providing a welcoming, inclusive environment for our workforce, with excellent training and career development opportunities to enable employees to thrive and achieve their career goals.

Corporate Information

The Company’s corporate website can be found at https://vitesse-vts.com/. The Company makes available free of charge at this website (under the “Investor Relations – SEC Filings” caption) copies of its reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, including its Annual Reports on Form 10-K, its Quarterly Reports on Form 10-Q, and its Current Reports on Form 8-K. In addition to its reports filed or furnished with the SEC, the Company publicly discloses material information from time to time in its press releases and Investor presentations, all of which are accessible through the website under the heading “Investor Relations” and the subheading “News & Events.” The Company’s Code of Business Conduct and Ethics, Corporate Governance Guidelines, and the charters of the Audit, Compensation, Nominating, Governance and Environmental and Social Responsibility Committees of the Board are available on the Company’s website under the heading “Investor Relations”, the subheading “Governance,” and the subheading “Governance Documents.” References to the Company's website in this Annual Report on Form 10-K are provided as a convenience and do not constitute, and should not be deemed, an incorporation by reference of the information contained on, or available through, the website, and such information should not be considered part of this Annual Report on Form 10-K.

Office Location

Our principal executive offices are located at 9200 E Mineral Ave, Suite 200, Centennial, CO 80112. Our current office space consists of approximately 15,000 square feet of leased space. We entered into a new office lease agreement in December 2022 which is expected to commence in 2024 for approximately 22,000 square feet of leased space located at 5619 DTC Parkway, Suite 700, Greenwood Village, CO 80111. We believe the new office space will be sufficient to meet our needs as well as support future growth as necessary.

Item 1A. Risk Factors

You should carefully consider the following risks and other information in this Annual Report on Form 10-K. The following risks have generally been separated into five groups: risks relating to our common stock, risks relating to our business, risks relating to our indebtedness, risks relating to the recent Spin-Off and risks relating to legal and regulatory matters. If any of the following events actually occur, our business, financial condition and results of operations could be materially adversely affected, the trading price of our common stock could decline and you could lose all or part of your investment. Additional risks and uncertainties that we do not presently know about or currently believe are not material may also adversely affect our business, financial condition and results of operations.

Summary Risk Factors

We believe that the risks associated with our business, and consequently the risks associated with an investment in our equity or debt securities, fall within the following categories:

Risks Relating to Our Common Stock

- Vitesse is an emerging growth company and the information we provide stockholders may be different from information provided by other public companies, which may result in a less active trading market for our common stock and higher volatility in our stock price.
- Although we expect to continue to pay dividends, we cannot provide assurance that we will pay dividends on our common stock, and our indebtedness may limit our ability to pay dividends on our common stock.
- Certain provisions in our Amended and Restated Certificate of Incorporation, Amended and Restated Bylaws and Delaware law may discourage takeovers.
- Your percentage ownership in Vitesse may be diluted in the future.
- Our Amended and Restated Certificate of Incorporation designate the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could may limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.

Risks Relating to Our Business

- Oil and natural gas prices are volatile. Extended declines in oil and natural gas prices have adversely affected, and could in the future adversely affect, our business, financial position, results of operations and cash flow.
- Due to previous declines in oil and natural gas prices, we have in the past taken writedowns of our oil and natural gas properties. We may be required to record further writedowns of our oil and natural gas properties in the future.
- Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our total reserves.
- 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 proved reserves.
- As a non-operator, the successful development and operation of our assets relies extensively on third parties, which could have an adverse effect on our financial condition and results of operations.
- The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we anticipate. Therefore, these undeveloped reserves may not be ultimately developed or produced.
- Our acquisition strategy will subject us to certain risks associated with the inherent uncertainty in evaluating properties for which we have limited information.
- The majority of our producing properties are located in the Williston Basin, making us vulnerable to risks associated with operating in one major geographic area.
- The loss of any member of our management team, upon whose knowledge, relationships with industry participants, leadership and technical expertise we rely, could diminish our ability to conduct our operations and harm our ability to execute our business plan.
- Deficiencies of title to our interests could significantly affect our financial condition.
- Inflation could adversely impact our ability to control our costs, including the operating expenses and capital costs of our operators.
- Our derivatives activities could adversely affect our profitability, cash flow, results of operations and financial condition.
- Asset retirement costs are difficult to predict and may be substantial. Unplanned costs could divert resources from other projects.
- Increased attention to ESG matters, including climate change, may impact our business and access to capital.

Risks Relating to Our Indebtedness

- Any significant reduction in the borrowing base under our Revolving Credit Facility may negatively impact our liquidity and could adversely affect our business and financial results.
- Our Revolving Credit Facility and other agreements governing indebtedness may contain operating and financial restrictions that may restrict our business and financing activities.
- Our ability to pay dividends to our stockholders is restricted by requirements under our Revolving Credit Facility.
- Variable rate indebtedness could subject us to interest rate risk, which could cause our debt service obligations to increase significantly.
- We may be adversely affected by developments in the SOFR market, changes in the methods by which SOFR is determined or the use of alternative reference rates.
- Our business plan requires the expenditure of significant capital, which we may be unable to obtain on favorable terms or at all.

Risks Relating to Legal and Regulatory Matters

- Restrictions on our ability to acquire federal leases and more stringent regulations affecting our operators' exploration and production activities on federal lands may adversely impact our business.
- Our business involves the selling and shipping of oil by rail, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.
- Our derivative activities expose us to potential regulatory risks.
- Failure to comply with federal, state and local environmental laws and regulations could result in substantial penalties and adversely affect our business.
- The adoption of climate change legislation or regulations restricting emissions of carbon dioxide, methane, and other greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Risks Relating to Tax Matters

- If the Distribution does not qualify as a transaction that is tax-free for U.S. federal income tax purposes, Jefferies and holders of Jefferies common stock who received shares of our common stock in connection with the Spin-Off could be subject to significant tax liability.
- Taxable gain or loss on the sale of our common stock could be more or less than expected.
- The IRS Forms 1099-DIV that our stockholders receive from their brokers may over-report dividend income with respect to our common stock for U.S. federal income tax purposes, which may result in a stockholder's overpayment of tax. In addition, failure to report dividend income in a manner consistent with the IRS Forms 1099-DIV may cause the IRS to assert audit adjustments to a stockholder's U.S. federal income tax return. For non-U.S. holders of our common stock, brokers or other withholding agents may overwithhold taxes from dividends paid, in which case a stockholder generally would have to timely file a U.S. tax return or an appropriate claim for refund to claim a refund of the overwithheld taxes.
- Some stockholders might be deemed to have received a taxable distribution as a result of our repurchase of our own stock.

We describe these and other risks in much greater detail below.

Risks Relating to Our Common Stock

An active, liquid trading market for our common stock may not continue, which may limit your ability to sell your shares.

Although we have listed our common stock on the NYSE under the symbol “VTS,” an active trading market for our common stock may not be sustained. A public trading market having the desirable characteristics of depth, liquidity and orderliness depends upon the existence of willing buyers and sellers at any given time, such existence being dependent upon the individual decisions of buyers and sellers over which neither we nor any market maker has control. The failure of an active and liquid trading market to continue would likely have a material adverse effect on the value of our common stock. An inactive market may also impair our ability to raise capital to continue to fund operations by issuing shares and may impair our ability to acquire other companies or assets by using our shares as consideration.

We cannot predict the prices at which our common stock may trade. The market price of our common stock may fluctuate widely, depending on many factors, some of which may be beyond our control, including:

- actual or anticipated fluctuations in our business, financial condition and results of operations due to factors related to our business;
- competition in the oil and natural gas industry and our ability to compete successfully;
- success or failure of our business strategies;
- our ability to retain and recruit qualified personnel;
- our quarterly or annual earnings, or those of other companies in our industry;
- our level of indebtedness, our ability to make payments on or service our indebtedness and our ability to obtain financing as needed;
- announcements by us or our competitors of significant acquisitions or dispositions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- the failure of securities analysts to continue to cover our common stock;
- changes in earnings estimates by securities analysts or our ability to meet those estimates;
- the operating and stock price performance of other comparable companies;
- investor perception of our company and the oil and natural gas industry;
- overall market fluctuations, including the cyclical nature of the oil and natural gas market;
- results from any material litigation or government investigation;
- changes in laws and regulations (including tax laws and regulations) affecting our business; and
- general economic conditions, credit and capital market conditions and other external factors.

Furthermore, low trading volume of and lack of liquidity for our stock may occur if, among other reasons, an active trading market does not continue. This would amplify the effect of the above factors on our stock price volatility.

Vitesse is an emerging growth company and the information we provide stockholders may be different from information provided by other public companies, which may result in a less active trading market for our common stock and higher volatility in our stock price.

Vitesse is an “emerging growth company” as defined by the Jumpstart Our Business Startups Act of 2012. We will continue to be an emerging growth company until the earliest to occur of the following:

- the last day of the fiscal year in which our total annual gross revenues first meet or exceed $1.235 billion (as adjusted for inflation);
- the date on which we have, during the prior three-year period, issued more than $1.0 billion in non-convertible debt;
- the last day of the fiscal year in which we (1) have an aggregate worldwide market value of common stock held by non-affiliates of $700 million or more (measured at the end of each fiscal year) as of the last business day of our most recently completed second fiscal quarter and (2) have been a reporting company under the Exchange Act for at least one year (and filed at least one annual report under the Exchange Act); or
- the last day of the fiscal year following the fifth anniversary of the date of the first sale of our common stock pursuant to an effective registration statement under the Securities Act.

For as long as we are an emerging growth company, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including, but not limited to:

- not being required to comply with the auditor attestation requirements in the assessment of our internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act of 2002;
- exemption from new or revised financial accounting standards applicable to public companies until such standards are also applicable to private companies;
- reduced disclosure obligations regarding executive compensation in our periodic reports, proxy statements and registration statements; and

- exemptions from the requirement of holding a nonbinding advisory vote on executive compensation and stockholder approval on golden parachute compensation not previously approved.

We may choose to take advantage of some or all of these reduced burdens. To the extent we take advantage of the reduced reporting obligations, the information we provide stockholders may be different from information provided by other public companies. In addition, it is possible that some investors will find our common stock less attractive as a result of these elections, which may result in a less active trading market for our common stock and higher volatility in our stock price.

In addition, we may take advantage of the extended transition period that allows an emerging growth company to delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. Our election to use the extended transition period may make it difficult to compare our financial statements to those of non-emerging growth companies and other emerging growth companies that have opted out of the extended transition period and who will comply with new or revised financial accounting standards.

Although we expect to continue to pay dividends, we cannot provide assurance that we will pay dividends on our common stock, and our indebtedness may limit our ability to pay dividends on our common stock.

The timing, declaration, amount of and payment of future dividends, if any, to stockholders will fall within the discretion of our Board. Our Board may change the timing and amount of any future dividend payments or eliminate the payment of future dividends to our stockholders at its discretion, without advance notice to our stockholders. Our Board's decisions regarding the payment of future dividends, if any, will depend upon many factors, including our financial condition, earnings, capital requirements of our business, covenants associated with certain of our debt service obligations, legal requirements or limitations, industry practice, and other factors deemed relevant by our Board. Our ability to declare and pay dividends to our stockholders is subject to certain laws and regulations, including minimum capital requirements and, as a Delaware corporation, we are subject to certain restrictions on dividends under the DGCL. Under the DGCL, our Board may not authorize payment of a dividend unless it is either paid out of our surplus, as calculated in accordance with the DGCL, or if we do not have a surplus, it is paid out of our net profits for the fiscal year in which the dividend is declared and/or the preceding fiscal year. For more information, see Part II. Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, - Dividend Policy. For a description of the covenants limiting our ability to pay dividends, see —Risks Relating to Our Indebtedness —Our ability to pay dividends to our stockholders is restricted by requirements under our Revolving Credit Facility. There can be no assurance that we will pay a dividend in the future or continue to pay any dividend.

Certain provisions in our Amended and Restated Certificate of Incorporation, Amended and Restated Bylaws and Delaware law may discourage takeovers.

Several provisions of our Amended and Restated Certificate of Incorporation, Amended and Restated Bylaws and Delaware law may discourage, delay or prevent a merger or acquisition that is opposed by our Board. These include provisions that:

- prevent our stockholders from calling a special meeting or acting by written consent;
- require advance notice of any stockholder nomination for the election of directors or any stockholder proposal;
- provide for a plurality voting standard in contested director elections;
- authorize only our Board to fill director vacancies and newly created directorships;
- authorize our Board to adopt, amend or repeal our Amended and Restated Bylaws without stockholder approval; and
- authorize our Board to issue one or more series of "blank check" preferred stock.

In addition, Section 203 of the DGCL prohibits a Delaware corporation from engaging in a business combination with any interested stockholder for a period of three years following the date the person became an interested stockholder, subject to certain exceptions. In general, Section 203 of the DGCL defines an "interested stockholder" as an entity or person who, together with the entity's or person's affiliates, beneficially owns, or is an affiliate of the corporation and within three years prior to the time of determination of interested stockholder status did own, 15% or more of the outstanding voting stock of the corporation. A Delaware corporation may "opt out" of these provisions with an express provision in its certificate of incorporation. We have not opted out of Section 203 of the DGCL in our Amended and Restated Certificate of Incorporation.

These and other provisions of our Amended and Restated Certificate of Incorporation, Amended and Restated Bylaws and Delaware law may discourage, delay or prevent certain types of transactions involving an actual or a threatened acquisition or change in control of us including unsolicited takeover attempts, even though the transaction may offer our stockholders the opportunity to sell their shares of our common stock at a price above the prevailing market price.

Your percentage ownership in Vitesse may be diluted in the future.

Your percentage ownership in Vitesse may be diluted in the future because of the settlement or exercise of equity-based awards that have been granted and that we expect will continue to be granted to our directors, officers and other employees under our equity incentive plan. In addition, we may issue equity as all or part of the consideration paid for acquisitions and strategic investments that we may make in the future or as necessary to finance our ongoing operations.

In addition, our Amended and Restated Certificate of Incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designation, powers, preferences and relative, participating, optional and other special rights, including preferences over our common stock with respect to dividends and distributions, as our Board may generally determine. The terms of one or more classes or series of preferred stock could dilute the voting power or reduce the value of our common stock. For example, we could grant the holders of preferred stock the right to elect some number of the members of our Board in all events or upon the happening of specified events, or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences that we could assign to holders of preferred stock could affect the residual value of our common stock.

Our Amended and Restated Certificate of Incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.

Our Amended and Restated Certificate of Incorporation provides that, in all cases to the fullest extent permitted by law, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will be the sole and exclusive forum for:

- any derivative action or proceeding brought on our behalf;
- any action or proceeding asserting a claim of breach of a fiduciary duty owed by any current or former director, officer or other employee or stockholder of our company to us or our stockholders;
- any action or proceeding asserting a claim arising pursuant to, or seeking to enforce any right, obligation or remedy under, any provision of Delaware law or our Amended and Restated Certificate of Incorporation or our Amended and Restated Bylaws; or
- any action or proceeding asserting a claim governed by the internal affairs doctrine or any other action asserting an "internal corporate claim" as that term is defined in Section 115 of the DGCL.

However, if the Court of Chancery of Delaware does not have jurisdiction, the action or proceeding may be brought in any other state or U.S. federal court located within the State of Delaware. Further, our Amended and Restated Certificate of Incorporation provides that, unless we consent in writing to the selection of an alternative forum, to the fullest extent permitted by law, the U.S. federal district courts are the sole and exclusive forum for any complaint asserting a cause of action arising under U.S. federal securities laws.

Any person holding, purchasing or otherwise acquiring shares of our stock will be deemed to have notice of and have consented to this provision and deemed to have waived any argument relating to the inconvenience of the forum in connection with any action or proceeding described in this provision. This provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits. Alternatively, if a court of competent jurisdiction were to find this provision of our Amended and Restated Certificate of Incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions.

Risks Relating to Our Business

Oil and natural gas prices are volatile. Extended declines in oil and natural gas prices have adversely affected, and could in the future adversely affect, our business, financial position, results of operations and cash flow.

The oil and natural gas markets are very volatile, and we cannot predict future oil and natural gas prices. Oil and natural gas prices have fluctuated significantly, including periods of rapid and material decline, in recent years. The prices we receive for our oil and natural gas production heavily influence our production, revenue, cash flows, profitability, reserve bookings and access to capital. Although we seek to mitigate volatility and potential declines in oil and natural gas prices through derivative arrangements that hedge a portion of our expected production, this merely seeks to mitigate (not eliminate) these risks, and such activities come with their own risks.

The prices we receive for our oil and natural gas production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- changes in NYMEX WTI oil prices and NYMEX Henry Hub natural gas prices;
- the volatility and uncertainty of regional pricing differentials;
- future repurchases (or additional possible releases) of oil from the strategic petroleum reserve by the United States Department of Energy;
- the actions of OPEC and other major oil producing countries;
- worldwide and regional economic, political and social conditions impacting the global supply and demand for oil and natural gas, which may be driven by various risks including war, terrorism, political unrest, or health epidemics;
- the price and quantity of imports of foreign oil and natural gas;

- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;
- the outbreak or escalation of military hostilities, including between Russia and Ukraine and in the Middle East, and the potential destabilizing effect such conflicts may pose for the global oil and natural gas markets;
- inflation;
- the level of global oil and natural gas exploration, production activity and inventories;
- changes in U.S. energy policy;
- weather conditions;
- outbreak of disease;
- technological advances affecting energy consumption;
- domestic and foreign governmental taxes, tariffs and/or regulations;
- proximity and capacity of processing, gathering, and storage facilities, oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas; and
- the price and availability of alternative fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict oil and natural gas prices. A substantial or extended decline in oil or natural gas prices, such as the significant and rapid decline that occurred in 2020, has resulted in and could result in future impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent oil and natural gas prices received from production are insufficient to fund planned capital expenditures, we may be required to reduce spending or borrow or issue additional equity to cover any such shortfall. Lower oil and natural gas prices may limit our ability to comply with the covenants under our Revolving Credit Facility and/or limit our ability to access borrowing availability thereunder, which is dependent on many factors including the value of our proved reserves.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our financial condition or results of operations.

Our operators' drilling activities are subject to many risks, including the risk that they will not discover commercially productive reservoirs. Drilling for oil or natural gas can be uneconomical, not only from dry holes, but also from productive wells that do not produce sufficient revenues to be commercially viable. In addition, drilling and producing operations on our acreage may be curtailed, delayed or canceled by our operators as a result of other factors, including:

- declines in oil or natural gas prices;
- infrastructure limitations, such as the natural gas gathering and processing constraints experienced in the Williston Basin in 2019;
- the high cost, shortages or delays of equipment, materials and services;
- unexpected operational events, pipeline ruptures or spills, adverse weather conditions and natural disasters, facility or equipment malfunctions, and equipment failures or accidents;
- title problems;
- pipe or cement failures and casing collapses;
- lost or damaged oilfield development and services tools;
- laws, regulations, and other initiatives related to environmental matters, including those addressing alternative energy sources, the phase-out of fossil fuel vehicles and the risks of global climate change;
- compliance with environmental and other governmental requirements;
- increases in severance taxes;
- regulations, restrictions, moratoria and bans on hydraulic fracturing;
- unusual or unexpected geological formations, and pressure or irregularities in formations;
- loss of drilling fluid circulations;
- environmental hazards, such as oil, natural gas or well fluids spills or releases, pipeline or tank ruptures and discharges of toxic gas;
- fires, blowouts, craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids; and
- pipeline capacity curtailments.

In addition to causing curtailments, delays and cancellations of drilling and producing operations, many of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells and regulatory penalties. We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

Due to previous declines in oil and natural gas prices, we have in the past taken writedowns of our oil and natural gas properties. We may be required to record further writedowns of our oil and natural gas properties in the future.

We review our oil and natural gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. We estimate the expected future cash flows of our oil and natural gas properties and compare such cash flows to the carrying amount of the proved oil and natural gas properties to determine if the amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust our proved oil and natural gas properties to estimated fair value. The factors used to estimate fair value include estimates of reserves, future oil and natural gas prices adjusted for basis differentials, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the projected cash flows. The discount rate is a rate that management believes is representative of current market conditions and includes estimates for a risk premium and other operational risks.

A continued period of low prices may force us to incur material write-downs of our oil and natural gas properties, which could have a material effect on the value of our properties and cause the value of our securities to decline. Additionally, impairments would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues. An impairment recognized in one period may not be reversed in a subsequent period even if higher oil and natural gas prices increase the cost center ceiling applicable to the subsequent period. We have in the past and could in the future incur impairments of oil and natural gas properties which may be material.

We have incurred net losses in the past, in part due to fluctuations in oil and gas prices, and we may incur such losses again in the future.

We had net loss of $19.7 million, net income of $118.9 million, net income of $18.1 million and net loss of $7.4 million during the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, respectively. To the extent our production is not hedged, we are exposed to declines in oil and natural gas prices, and our derivative arrangements may be inadequate to protect us from continuing and prolonged declines in oil and natural gas prices. In prior periods, such declines have led to net losses. Unrealized hedging losses on commodity derivatives attributable to significant increases in oil prices may also cause a net loss for a given period.

In addition, fluctuations in oil and natural gas prices have impacted our Predecessor unit-based compensation expense for prior periods and may impact our stock-based compensation expense. For example, in prior periods we have experienced increases to our unit-based compensation expense primarily due to increased oil and natural gas prices causing the estimated fair value of the liabilities associated with such unit-based compensation to increase, which contributed to net losses recorded during such periods. As a result of the foregoing and other factors, we may continue to incur net losses in the future.

Our estimated proved reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our total reserves.

Determining the amount of oil and natural gas recoverable from various formations involves significant complexity and uncertainty. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating, and development costs. Some of our reserve estimates are made without the benefit of a lengthy production history and are less reliable than estimates based on a lengthy production history. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate.

We routinely make estimates of oil and natural gas reserves in connection with managing our business, including in some cases estimates prepared by our internal reserve engineers and professionals that are not reviewed or audited by an independent reserve engineering firm. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, development schedules, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, reserve engineers and other advisors to make accurate assumptions. Any significant variance from these assumptions by actual figures could greatly affect our estimates of total reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based result in the actual quantities of oil and natural gas our operators ultimately recover being different from our reserve estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K, subsequent reports we file with the SEC or other company materials.

Our future success depends on our ability to replace reserves.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as our reserves are produced. We have added significant net wells and production from wellbore-only acquisitions, where we don't hold the underlying leasehold interest that would entitle us to participate in future wells. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

We may acquire significant amounts of unproved property to further our development efforts. Development and drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We seek to acquire both proved and producing properties as well as undeveloped acreage that we believe will enhance growth potential and increase our earnings over time. However, we cannot assure you that all of these properties will contain economically viable reserves or that we will not abandon existing properties. Additionally, we cannot assure you that unproved reserves or undeveloped acreage that we acquire will be profitably developed, that new wells drilled on our properties will be productive or that we will recover all or any portion of our capital in our properties and reserves.

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 proved reserves.

We base the estimated discounted future net cash flows from our proved reserves using Standardized Measure and PV-10, each of which uses specified pricing and cost assumptions. However, actual future net cash flows from our oil and natural gas properties will be affected by factors such as the volume, pricing and duration of our hedging contracts; actual prices we receive for oil and natural gas; our actual operating costs in producing oil and natural gas; the amount and timing of our capital expenditures; the amount and timing of actual production; and changes in governmental regulations or taxation. For example, our estimated proved reserves as of December 31, 2023 were calculated under SEC rules by applying year-end SEC prices based on the twelve-month unweighted arithmetic average of the first day of the month oil and natural gas prices for such year end of $78.21 per Bbl and $2.64 per MMBtu, which for certain periods during this time were substantially different from the available market prices. In addition, the 10% discount factor we use when calculating discounted future net cash flows 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 natural gas industry in general. Any material inaccuracies in these 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 business depends on transportation and processing facilities and other assets that are owned by third parties.

The marketability of our oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems, processing facilities, oil trucking fleets and rail transportation assets owned by third parties. The lack of available capacity on these systems and facilities, whether as a result of proration, growth in demand outpacing growth in capacity, physical damage, scheduled maintenance, legal or other reasons such as suspension of service due to legal challenges (see below regarding the Dakota Access Pipeline), could result in a substantial increase in costs, declines in realized oil and natural gas prices, the shut-in of producing wells or the delay or discontinuance of development plans for our properties. In recent periods, we experienced significant delays and production curtailments, and declines in realized natural gas prices, that we believe were due in part to natural gas gathering and processing constraints in the Williston Basin. The negative effects arising from these and similar circumstances may last for an extended period of time. In many cases, operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, our wells may be drilled in locations that are serviced to a limited extent, if at all, by gathering and transportation pipelines, which may or may not have sufficient capacity to transport production from all of the wells in the area. As a result, we rely on third-party oil trucking to transport a significant portion of our production to third-party transportation pipelines, rail loading facilities and other market access points. In addition, the third parties on whom operators rely for transportation services are subject to complex federal, state, tribal, and local laws that could adversely affect the cost, manner, or feasibility of conducting business on our oil and natural gas properties. Further, concerns about the safety and security of oil and gas transportation by pipeline may result in public opposition to pipeline development and increased regulation of pipelines by PHMSA. In recent years, PHMSA has increased regulation of onshore gas transmission systems, hazardous liquids pipelines, and gas gathering systems. For example, in November 2021, PHMSA issued a final rule that extended pipeline safety requirements to onshore gas gathering pipelines, and therefore could result in less capacity to transport our products by pipeline. Additional regulation could impact rates charged by our operators and impact their ability to enter into gathering and transportation agreements, which costs could be passed through to us.

The Dakota Access Pipeline (the "DAPL"), a major pipeline transporting oil from the Williston Basin, is subject to ongoing litigation that could threaten its continued operation. In July 2020, a federal district court vacated the DAPL's easement to cross the Missouri River at Lake Oahe and ordered the pipeline be shut down pending the completion of an environmental impact statement ("EIS") to determine whether the DAPL poses a threat to the Missouri River and drinking water supply of the Standing Rock Sioux Reservation. The shut-down order was later reversed on appeal and the DAPL currently remains in operation while the Corps completes the EIS, a draft of which was completed in 2023, opened to public comment through December 2023, and is expected to be finalized in spring or summer 2024. Following completion of the EIS, the Corps will issue a final decision whether to grant the DAPL an easement to cross the Missouri River at Lake Oahe or to require the abandonment, removal, or reroute of that section, effectively shutting down the pipeline. Moreover, the EIS or the Corps' decision with respect to an easement may subsequently be challenged in court. As a result, a shut-down remains possible, and there is no guarantee that the DAPL will be permitted to continue operations following the completion of the EIS. Any significant curtailment in gathering system or pipeline capacity, or the unavailability of sufficient third-party trucking or rail capacity, could adversely affect our business, results of operations and financial condition.

Seasonal weather conditions, extreme climatic events, and shifts in meteorological conditions, which may be impacted by climate change, may adversely affect our operators' ability to conduct drilling and completion activities and to sell oil and natural gas for periods of time or affect demand for oil and gas, in some of the areas where our properties are located.

Seasonal weather conditions can limit drilling and completion activities, selling oil and natural gas, and other operations in some of our operating areas. In the Williston Basin, drilling and other oil and natural gas activities on our properties can be adversely affected during the winter months by severe winter weather and drilling on our properties is generally performed during the summer and fall months. These seasonal constraints can pose challenges for meeting well drilling objectives and increase competition for equipment, supplies and personnel during the summer and fall months, which could lead to shortages and increase costs or delay operations. Additionally, many municipalities impose weight restrictions on the paved roads that lead to jobsites due to the muddy conditions caused by spring thaws. This could limit access to jobsites and operators' ability to service wells in these areas.

The frequency and severity of severe winter weather conditions and shifts in regional temperature and precipitation patterns, which could result in increases in severity or frequency of droughts, storms, flooding, or wildfires, could cause physical damage to our operators' assets, disrupt our operators' supply chains (for example, through water use curtailments imposed during a prolonged drought), or otherwise adversely impact the production activities on our interests. Such climatic events may also be impacted or exacerbated by the effects of climate change. The ability of our operators to mitigate the adverse impacts of these events depends in part on the effectiveness of their resiliency planning in design and disaster preparedness and response, which may not have considered every eventuality. Additionally, global climate trends and changes in meteorological conditions may result in changes to the amount, timing, or location of demand for energy or its production. To the extent these events occur, our production from our assets and our resulting financial condition and performance could be adversely affected.

As a non-operator, the successful development and operation of our assets relies extensively on third parties, which could have an adverse effect on our financial condition and results of operations.

We have only participated in wells operated by third parties. The success of our business operations depends on the timing of drilling activities and success of our third-party operators. If our operators are not successful in the development, exploitation, production and exploration activities relating to our leasehold interests, or are unable or unwilling to perform, our financial condition and results of operations would be adversely affected.

These risks are heightened in a low oil and natural gas price environment, which may present significant challenges to our operators. The challenges and risks faced by our operators may be similar to or greater than our own, including with respect to their ability to service their debt, remain in compliance with their debt instruments and, if necessary, access additional capital. Oil and natural gas prices and/or other conditions have in the past and may in the future cause oil and natural gas operators to file for bankruptcy. The insolvency of an operator of any of our properties, the failure of an operator of any of our properties to adequately perform operations or an operator's breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and natural gas leases jointly owned with the operator or another insolvent owner.

Our operators will make decisions in connection with their operations (subject to their contractual and legal obligations to other owners of working interests), which may not be in our best interests. We may have no ability to exercise influence over the operational decisions of our operators, including the setting of capital expenditure budgets and drilling locations and schedules. Dependence on our operators could prevent us from realizing our target returns for those locations. The success and timing of development activities by our operators will depend on a number of factors that will largely be outside of our control, including oil and natural gas prices and other factors generally affecting the oil and natural gas industry's operating environment; the timing and amount of capital expenditures; their expertise and financial resources; approval of other participants in drilling wells; selection of technology; and the rate of production of reserves, if any.

The inability of one or more of our operators to meet their financial obligations to us may adversely affect our financial results.

Our exposures to credit risk are, in part, through receivables resulting from the sale of our oil and natural gas production, which operators market on our behalf to energy marketing companies, refineries and their affiliates. We are subject to credit risk due to the relative concentration of our oil and natural gas receivables with a limited number of operators. This concentration may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. A low oil and natural gas price environment may strain our operators, which could heighten this risk. The inability or failure of our operators to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

We could experience periods of higher costs as activity levels fluctuate or if oil and natural gas prices rise. These increases could reduce our profitability, cash flow, and ability to complete development activities as planned.

An increase in oil and natural gas prices or other factors could result in increased development activity and investment in our areas of operations, which may increase competition for and cost of equipment, labor and supplies. Shortages of, or increasing costs for, experienced drilling crews and equipment, labor or supplies could restrict our operators' ability to conduct desired or expected operations. In addition, capital and operating costs in the oil and natural gas industry have generally risen during periods of increasing oil and natural gas prices as producers seek to increase production in order to capitalize on higher oil and natural gas prices. In situations where cost inflation exceeds oil and natural gas price inflation, our profitability and cash flow, and our operators' ability to complete development activities as scheduled and on budget, may be negatively impacted. Any delay in drilling or significant increase in drilling costs could reduce our revenues and profitability.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we anticipate. Therefore, these undeveloped reserves may not be ultimately developed or produced.

Approximately 30% of our estimated net proved reserves volumes were classified as proved undeveloped as of December 31, 2023. Development of undeveloped reserves may take longer and require higher levels of capital expenditures than we anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

Our acquisition strategy will subject us to certain risks associated with the inherent uncertainty in evaluating properties for which we have limited information.

We intend to continue to expand our operations in part through acquisitions. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not economically feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential recoverable reserves. On-site inspections are often not performed on properties being acquired, and environmental matters, such as subsurface contamination, are not necessarily observable even when an on-site inspection is undertaken. Any acquisition involves other potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, revenues and costs;
- a decrease in our liquidity by using a significant portion of our cash from operations or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the ultimate value of any contingent consideration agreed to be paid in an acquisition;
- dilution to stockholders if we use equity as consideration for, or to finance, acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- geological risk, which refers to the risk that hydrocarbons may not be present or, if present, may not be recoverable economically;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets; and
- an increase in our costs or a decrease in our revenues associated with any potential royalty owner or landowner claims or disputes, or other litigation encountered in connection with an acquisition.

We may also acquire multiple assets in a single transaction. Portfolio acquisitions via joint-venture or other structures are more complex and expensive than single project acquisitions, and the risk that a multiple-project acquisition will not close may be greater than in a single-project acquisition. An acquisition of a portfolio of projects may result in our ownership of projects in geographically dispersed markets which place additional demands on our ability to manage such operations. A seller may require that a group of projects be purchased as a package, even though one or more of the projects in the portfolio does not meet our strategic objectives. In such cases, we may attempt to make a joint bid with another buyer, and such other buyer may default on its obligations.

Further, we may acquire properties subject to known or unknown liabilities and with limited or no recourse to the former owners or operators. As a result, if liability were asserted against us based upon such properties, we may have to pay substantial sums to dispute or remedy the matter, which could adversely affect our profitability. Unknown liabilities with respect to assets acquired could include, for example: liabilities for clean-up of undiscovered or undisclosed environmental contamination; claims by developers, site owners, vendors or other persons relating to the asset or project site; liabilities incurred in the ordinary course of business; and claims for indemnification by general partners, directors, officers and others indemnified by the former owners of the asset or project sites.

Our business plan requires the expenditure of significant capital, which we may be unable to obtain on favorable terms or at all.

Our acquisition and development activities require substantial capital expenditures. Historically, we have funded our capital expenditures through a combination of cash flow from operations, borrowings under our credit facilities and equity issuances. Cash reserves, cash flow from operations and borrowings under our Revolving Credit Facility may not be sufficient to fund our continuing operations and business plan and goals. We may require additional capital and we may be unable to obtain such capital if and when required. If our access to capital were limited due to numerous factors, which could include a decrease in operating cash flow due to lower oil and natural gas prices or decreased production or deterioration of the credit and capital markets, we would have a reduced ability to develop our properties, replace our reserves and pursue our business plan and goals. We may not be able to incur additional debt under our Revolving Credit Facility, issue debt or equity, engage in asset sales or access other methods of financing on acceptable terms or at all. If the amount of capital we are able to raise from financing activities, together with our cash flow from operations, is not sufficient to satisfy our capital requirements, we may not be able to implement our business plan and may be required to scale back our operations, sell assets at unattractive prices or obtain financing on unattractive terms, any of which could adversely affect our business, results of operations and financial condition.

We may be unable to successfully integrate any assets we may acquire in the future into our business or achieve the anticipated benefits of such acquisitions.

We may not be able to integrate the acquired assets into our existing business in an efficient and effective manner or achieve the anticipated benefits of such acquisitions. We may not be able to accomplish this integration process successfully. The successful acquisition of properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- availability and cost of transportation of production to markets;
- availability and cost of drilling equipment and of skilled personnel;
- development and operating costs including access to water and potential environmental and other liabilities; and
- regulatory, permitting and similar matters.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform reviews of the subject properties that we believe to be generally consistent with industry practices. The reviews are based on our analysis of historical production data, assumptions regarding capital expenditures and anticipated production declines without review by an independent petroleum engineering firm. Data used in such reviews are typically furnished by the seller or obtained from publicly available sources. Our review may not reveal all existing or potential problems or permit us to fully assess the deficiencies and potential recoverable reserves for all of the acquired properties, and the reserves and production related to the acquired properties may differ materially after such data is reviewed by an independent petroleum engineering firm or further by us. On-site inspections will not always be performed on every well, and environmental problems are not necessarily observable even when an on-site inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or a portion of the underlying deficiencies. We are often not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis, and, as is the case with certain liabilities associated with the assets acquired in our recent acquisitions, we are entitled to indemnification for only certain operational liabilities. The integration process may be subject to delays or changed circumstances, and we can give no assurance that our acquired assets will perform in accordance with our expectations or that our expectations with respect to integration or the benefits of such acquisitions will materialize.

The majority of our producing properties are located in the Williston Basin, making us vulnerable to risks associated with operating in one major geographic area.

Our oil and natural gas properties are focused on the Williston Basin, which means our current producing properties and new drilling opportunities are geographically concentrated in that area. Because our oil and natural gas properties are not as diversified geographically as some of our competitors, our profitability may be disproportionately exposed to the effect of any regional events, including fluctuations in prices of oil and natural gas produced from the wells in the region, natural disasters, restrictive governmental regulations, transportation capacity constraints, weather, curtailment of production or interruption of transportation and processing, and any resulting delays or interruptions of production from existing or planned new wells.

The loss of any member of our management team, upon whose knowledge, relationships with industry participants, leadership and technical expertise we rely, could diminish our ability to conduct our operations and harm our ability to execute our business plan.

Our success depends heavily upon the continued contributions of those members of our management team whose knowledge, relationships with industry participants, leadership and technical expertise would be difficult to replace. In particular, our ability to successfully acquire additional properties, to increase our reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements depends on developing and maintaining close working relationships with industry participants. In addition, our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment is dependent on our management team's knowledge and expertise in the industry. To continue to develop our business, we rely on our management team's knowledge and expertise in the industry and will use our management team's relationships with industry participants to enter into strategic relationships. The members of our management team may terminate their employment with our company at any time. If we were to lose members of our management team, we may not be able to replace the knowledge or relationships that they possess and our ability to execute our business plan could be materially harmed.

Deficiencies of title to our leased interests could significantly affect our financial condition.

We typically do not incur the expense of a title examination prior to acquiring oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights. If an examination of the title history of a property reveals that an oil or natural gas lease or other developed rights have been purchased in error from a person who is not the owner of the interest desired, our interest would substantially decline in value or be eliminated. In such cases, the amount paid for such oil or natural gas lease or leases or other developed rights may be lost. It is generally our practice not to incur the expense of retaining lawyers to examine the title to the interest to be acquired. Rather, we typically rely upon the judgment of our own oil and natural gas landmen who conduct due diligence and perform the fieldwork in examining records in the appropriate governmental or county clerk's office before attempting to acquire a lease or other developed rights in a specific interest.

Prior to drilling an oil or natural gas well, however, it is the normal practice in the oil and natural gas industry for the company acting as the operator of the well to obtain a title examination of the spacing unit within which the proposed oil or natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, such as obtaining affidavits of heirship or causing an estate to be administered. Such curative work entails expense, and the operator may elect to proceed with a well despite defects to the title identified in the title opinion. Furthermore, title issues may arise at a later date that were not initially detected in any title review or examination. Any one or more of the foregoing could require us to reverse revenues previously recognized and potentially negatively affect our cash flows and results of operations. Our failure to obtain perfect title to our leaseholds may adversely affect our production and reserves and our ability in the future to increase production and reserves.

We conduct business in a highly competitive industry.

The oil and natural gas industry is highly competitive. The key areas in respect of which we face competition include: acquisition of assets offered for sale by other companies; access to capital (debt and equity) for financing and operational purposes; purchasing, leasing, hiring, chartering or other procuring of equipment by our operators that may be scarce; and employment of qualified and experienced skilled management and oil and natural gas professionals.

Competition in our markets is intense and depends, among other things, on the number of competitors in the market, their financial resources, their degree of geological, geophysical, engineering and management expertise and capabilities, their pricing policies, their ability to develop properties on time and on budget, their ability to select, acquire and develop reserves and their ability to foster and maintain relationships.

Our competitors include entities with greater technical, physical and financial resources. In addition, companies and certain private equity firms not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Any such companies will also increase market competition which may directly affect us. If we are unsuccessful in competing against other companies, our business, results of operations, financial condition or prospects could be materially adversely affected.

Global pandemics have previously, may continue to, and may in the future adversely impact our financial condition and results of operations.

Global pandemics, including the COVID-19 pandemic, and the actions taken by governmental authorities, businesses and consumers in response to such pandemics, including travel bans, prohibitions on group events and gatherings, shutdowns of certain businesses, curfews, shelter-in-place orders and recommendations to practice social distancing, have previously and could in the future have an adverse impact on international and U.S. economic activity which results in significant volatility in the oil and gas industry.

The extent to which our operating and financial results are affected by pandemic will depend on various factors and consequences beyond our control, such as the duration and scope of the pandemic, additional actions by businesses and governments in response to the pandemic, and the speed and effectiveness of responses to combat the pandemic. Furthermore, such pandemics, and the volatile regional and global economic conditions stemming from them, could also aggravate the other risk factors that we identify herein.

The ongoing military conflicts in Ukraine and the Middle East have caused unstable market and economic conditions and are expected to have additional global consequences. Our business, financial condition, and results of operations may be materially adversely affected by the negative global and economic impact resulting from such military conflicts or any other geopolitical tensions.

U.S. and global markets are experiencing volatility and disruption following the escalation of geopolitical tensions, the ongoing military conflict between Russia and Ukraine and escalation of hostilities in the Middle East. Although the length and impact of these ongoing military conflicts are highly unpredictable, the military conflicts in Ukraine and in the Middle East have led to market disruptions, including significant volatility in oil and natural gas prices, credit and capital markets, as well as supply chain disruptions. These disruptions in the oil and natural gas markets have caused, and could continue to cause, significant volatility in energy prices, which could have a material effect on our business.

Prolonged unfavorable economic conditions or uncertainty as a result of these military conflicts may adversely affect our business, financial condition, and results of operations. Any of the foregoing may also magnify the impact of other risks described in this Annual Report on Form 10-K.

Inflation could adversely impact our ability to control our costs, including the operating expenses and capital costs of our operators.

Although inflation in the United States has been relatively low in recent years, it rose significantly beginning in the second half of 2021 and has continued to rise in 2022 and 2023. This is believed to be the result of the economic impact from global supply chain disruptions, among other factors. Global, industry-wide supply chain disruptions have resulted in shortages in labor, materials and services. Such shortages have resulted in inflationary cost increases for labor, materials and services and could continue to cause costs to increase as well as scarcity of certain products and raw materials. To the extent elevated inflation remains, our operators may experience further cost increases for their operations, including oilfield services, labor costs, and equipment if drilling activity in our operators' areas of operations increases. Higher oil and natural gas prices may cause the costs of materials and services to continue to rise. We cannot predict any future trends in the rate of inflation and a significant increase in inflation, to the extent we are unable to recover higher costs through higher oil and natural gas prices and revenues, would negatively impact our business, financial condition and results of operations.

Adverse developments affecting the financial services industry, such as actual events or concerns involving liquidity, defaults, or non-performance by financial institutions or transactional counterparties, could adversely affect our current and projected business operations and our financial condition and results of operations.

Actual events involving limited liquidity, defaults, non-performance or other adverse developments that affect financial institutions, transactional counterparties or other companies in the financial services industry or the financial services industry generally, or concerns or rumors about any events of these kinds or other similar risks, have in the past and may in the future lead to market-wide liquidity problems. For example, on March 10, 2023, SVB was closed by the California Department of Financial Protection and Innovation, which appointed the Federal Deposit Insurance Corporation ("FDIC") as receiver. Similarly in 2023, Signature Bank, Silvergate Capital Corp. and First Republic Bank were each placed into receivership by the FDIC. Although we did not have any funds deposited with SVB, Signature Bank, [Silvergate Capital Corp] or First Republic Bank, we currently, and may in the future, have assets held at financial institutions that may exceed the insurance coverage offered by the FDIC, and the loss of such assets would have a severe negative affect on our operations and liquidity. In addition, if any of our counterparties with whom we conduct business are unable to access funds pursuant to such instruments or lending arrangements with such a financial institution, such parties' ability to pay their obligations to us or to enter into new commercial arrangements requiring additional payments to us could be adversely affected. Our primary banking relationship is with Wells Fargo Bank, as administrative agent and lender, and a syndicate of banks, as additional lenders under the Revolving Credit Facility including Fifth Third Bank, Bank of Oklahoma, and Amegy Bank.

Our derivatives activities could adversely affect our profitability, cash flow, results of operations and financial condition.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the price of oil and natural gas, we enter into derivative instrument contracts for a portion of our expected production, which may include swaps, collars, puts and other structures. See Part II. Item 7A. Quantitative and Qualitative Disclosure About Market Risk - Commodity Price Risk. By using derivative instrument contracts to reduce our exposure to adverse fluctuations in the price of oil and natural gas, we could limit the benefit we would receive from increases in the prices for oil and natural gas, which could have an adverse effect on our profitability, cash flow, results of operations and financial condition. Likewise, to the extent our production is not hedged, we are exposed to declines in oil and natural gas prices, and our derivative arrangements may be inadequate to protect us from continuing and prolonged declines in oil and natural gas prices. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and they are included on our balance sheet as assets or liabilities and in our statements of operations as gain (loss) on commodity derivatives, net. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair market value of our derivative instruments. In addition, while intended to mitigate the effects of volatile oil and natural gas prices, our derivatives transactions may limit our potential gains and increase our potential losses if oil and natural gas prices were to rise substantially over the price established by the hedge.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for such period. If the actual amount of production is higher than we estimate, we will have greater oil and natural gas price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which a counterparty to our derivative contracts is unable to satisfy its obligations under the contracts; our production is less than expected; or there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make it unable to perform under the terms of the contracts, and we may not be able to realize the benefit of the contracts. We may be unable to predict changes in a counterparty’s creditworthiness or ability to perform. Even if we do accurately predict changes, our ability to negate the risk may be limited depending upon market conditions.

Asset retirement costs are difficult to predict and may be substantial. Unplanned costs could divert resources from other projects.

We are responsible for costs associated with plugging, abandoning and reclaiming wells, pipelines and other facilities that we use for production of oil and natural gas reserves where we have a working interest. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as “asset retirement.” We accrue a liability for asset retirement costs associated with our wells, but have not established any cash reserve account for these potential costs in respect of any of our properties. It may be difficult for us to predict such asset retirement costs. If asset retirement is required before economic depletion of our properties or if our estimates of the costs of asset retirement exceed the value of the reserves remaining at any particular time to cover such asset retirement costs, we may have to draw on funds from other sources to satisfy such costs, which may be substantial. The use of other funds to satisfy such asset retirement costs could impair our ability to dedicate our capital to other areas of our business.

We depend on computer and telecommunications systems, and failures in our systems or cybersecurity threats, attacks or other disruptions could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed or may develop proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible that we, or these third parties, could incur interruptions from cybersecurity attacks, computer viruses or malware, or that third-party service providers could cause a breach of our data. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties for our computing and communications infrastructure or any other interruptions to, or breaches of, our information systems could lead to data corruption, communication interruption, loss of sensitive or confidential information or otherwise significantly disrupt our business operations. Although we utilize various procedures and controls to monitor these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. Furthermore, various third-party resources that we rely on, directly or indirectly, in the operation of our business (such as pipelines and other infrastructure) could suffer interruptions or breaches from cyber-attacks or similar events that are entirely outside our control, and any such events could significantly disrupt our business operations and/or have a material adverse effect on our results of operations. To our knowledge we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer material losses in the future.

In addition, our operators face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of their facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to operations and could have a material adverse effect on our financial position, results of operations or cash flows. The U.S. government has issued warnings that U.S. energy assets may be the future targets of terrorist organizations. These developments subject operations on our oil and natural gas properties to increased risks. Any future terrorist attack at our operators' facilities, or those of their purchasers or vendors, could have a material adverse effect on our financial condition and operations.

Decarbonization measures and related governmental initiatives, technological advances, increased competitiveness of alternative energy sources and negative shift in market perception towards the oil and natural gas industry could reduce demand for oil and natural gas.

Decarbonization measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices, and the increased competitiveness of alternative energy sources could reduce demand for oil and natural gas. Additionally, the increased competitiveness of alternative energy sources (such as wind, solar, geothermal, tidal, fuel cells and biofuels) could reduce demand for oil and natural gas and, therefore, our revenues.

Our business could also be impacted by governmental initiatives to encourage the conservation of energy or the use of alternative energy sources. For example, in November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; eliminating subsidies provided to the fossil fuel industry; reducing non-CO2 GHG emissions, such as methane and nitrous oxide; and increasing the emphasis on climate-related risks across government agencies and economic sectors. In addition, the IRA includes a variety of clean-energy tax credits and establishes a program designed to reduce methane emissions from oil and gas operations. These initiatives or similar state or federal initiatives to reduce energy consumption or encourage a shift away from fossil fuels could reduce demand for hydrocarbons and have a material adverse effect on our earnings, cash flows and financial condition.

Additionally, certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry. Some organizations that provide information to investors on corporate governance and related matters have developed ratings investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries. Furthermore, certain other stakeholders have pressured commercial and investment banks to stop funding oil and natural gas projects. With the continued volatility in oil and natural gas prices, and the possibility that interest rates may continue to rise in the near term, increasing the cost of borrowing, certain investors have emphasized capital efficiency and free cash flow from earnings as key drivers for energy companies, especially shale producers. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

The impact of the changing demand for oil and natural gas services and products, together with a change in investor sentiment, may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Increased attention to ESG matters, including climate change, may impact our business and access to capital.

Businesses across all industries are facing increasing scrutiny from stakeholders related to their ESG practices. Businesses that do not adapt to or comply with investor or stakeholder expectations and standards, which are continuing to evolve, or businesses that are perceived to have not responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, may suffer from reputational damage and the business, financial condition, and/or stock price of such business entity could be materially and adversely affected. Increasing attention to climate change, increasing societal expectations on companies to address climate change, increasing investor and societal expectations regarding voluntary ESG disclosures, increasing mandatory ESG disclosures, and increasing consumer demand for alternatives to oil and natural gas may result in increased costs, reduced demand for our products, reduced profits, increased administrative, legislative, and judicial scrutiny, reputational damage, and negative impacts on our access to capital markets. To the extent that societal pressures or political or other factors are involved, it is possible that the Company could be subject to additional governmental investigations, private litigation or activist campaigns as stockholders may attempt to effect changes to the Company's business or governance practices.

As part of our ongoing effort to enhance our ESG practices, our Board has established the Nominating, Governance and Environmental and Social Responsibility Committee, which is charged with overseeing our ESG risks, strategies, policies, and programs in the best interests of our stakeholders. While we may elect pursue to certain ESG strategies in the future, the goals of such are aspirational and may not have the intended impact on our business. We may also receive pressure from investors, lenders or other groups to adopt more aggressive climate or other ESG-related goals, but we cannot guarantee that we will be able to implement such goals because of potential costs or technical or operational obstacles. Moreover, failure or a perception (whether or not valid) of failure to implement ESG strategies or achieve ESG goals or commitments, including any GHG emission reduction or carbon intensity goals or commitments, could result in private litigation and damage our reputation, cause investors or consumers to lose confidence in us, and negatively impact our operations.

Also, institutional lenders may, of their own accord, decide not to provide funding for fossil fuel energy companies or related infrastructure projects based on climate or other ESG-related concerns, which could affect our access to capital for potential growth projects. Many of the largest U.S. banks and other large institutional investors have made “net zero” carbon emission commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps to quantify and reduce those emissions. Additionally, there is also a risk that financial institutions will be pressured or required to adopt policies that have the effect of reducing the capital provided to the fossil fuel sector. In 2023 the six largest U.S. banks performed a pilot climate scenario exercise pursuant to instructions published by the Federal Reserve. The SEC has proposed rules that would mandate extensive disclosure of climate risks, including financial impacts, physical and transition risks, related climate-related governance and strategy, and GHG emissions, for all U.S.-listed public companies. Enhanced climate disclosure requirements could result in additional legal and accounting costs and accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors. States may also pass laws imposing more expansive disclosure requirements for climate-related risks. Separately, the SEC has also announced that it is scrutinizing existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer’s existing climate disclosures misleading or deficient. New laws, regulations, or enforcement initiatives related to the disclosure of climate-related risks could lead to reputational or other harm with customers, regulators, lenders, investors or other stakeholders and could also increase litigation risks. Any material reduction in the capital available to the fossil fuel industry could make it more difficult to secure funding for exploration, development, production, transportation, and processing activities, which could impact our business and results of operations.

Risks Relating to Our Indebtedness

Any significant reduction in the borrowing base under our Revolving Credit Facility may negatively impact our liquidity and could adversely affect our business and financial results.

Availability under our Revolving Credit Facility is subject to a borrowing base, with scheduled semiannual and other elective borrowing base redeterminations based upon, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing the Revolving Credit Facility. As a result of these borrowing base redeterminations, the lenders under the Revolving Credit Facility are able to unilaterally determine and adjust the borrowing base and the borrowings permitted to be outstanding under our Revolving Credit Facility. Reductions in estimates of our producing oil and natural gas reserves could result in a reduction of our borrowing base thereunder. The same could also arise from other factors, including but not limited to lower commodity prices or production; operating difficulties; changes in oil and natural gas reserve engineering; increased operating and/or capital costs; lending requirements or regulations; or other factors affecting our lenders’ ability or willingness to lend (including factors that may be unrelated to our company). Any significant reduction in our borrowing base could result in a default under current and/or future debt instruments, negatively impact our liquidity and our ability to fund our operations and, as a result, could have a material adverse effect on our financial position, results of operations and cash flow. Further, if the outstanding borrowings under our Revolving Credit Facility were to exceed the borrowing base as a result of any such redetermination, we could be required to repay the excess. If we do not have sufficient funds and we are otherwise unable to arrange new financing, we may have to sell significant assets or take other actions. Any such sale or other actions could have a material adverse effect on our business and financial results.

Our Revolving Credit Facility and other agreements governing indebtedness may contain operating and financial restrictions that may restrict our business and financing activities.

Our Revolving Credit Facility contains a number of restrictive covenants that impose operating and financial restrictions on us, including restrictions on our ability to, among other things: declare or pay any dividend or make any other distributions on, purchase or redeem our equity interests; make loans or certain investments; make certain acquisitions; incur or guarantee additional indebtedness or issue certain types of equity securities; incur liens; transfer or sell assets; create subsidiaries; consolidate, merge or transfer all or substantially all of our assets; and engage in transactions with our affiliates. For a description of the covenants limiting our ability to pay dividends, see —Our ability to pay dividends to our stockholders is restricted by requirements under our Revolving Credit Facility. In addition, the Revolving Credit Facility requires us to maintain compliance with certain financial covenants and other covenants. As a result of these covenants, we could be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with these covenants and restrictions may be affected by events beyond our control, including the deterioration of market or other economic conditions. A failure to comply with the covenants, ratios or tests in our Revolving Credit Facility or any other indebtedness could result in an event of default, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. If an event of default under our Revolving Credit

Facility occurs and remains uncured, the lenders thereunder would not be required to lend any additional amounts to us and could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be immediately due and payable. If the payment of debt were accelerated, cash flows from our operations may be insufficient to repay such debt in full and our stockholders could experience a partial or total loss of their investment. Our Revolving Credit Facility contains customary events of default, including the occurrence of a change in control.

An event of default or an acceleration under our Revolving Credit Facility could result in an event of default and an acceleration under other existing or future indebtedness. Conversely, an event of default or an acceleration under any other existing or future indebtedness could result in an event of default and an acceleration under our Revolving Credit Facility. In addition our obligations under the Revolving Credit Facility are collateralized by perfected liens and security interests on substantially all of our assets and if we default thereunder, the lenders could seek to foreclose on our assets.

We may not be able to generate enough cash flow to meet our debt obligations or to pay dividends to our stockholders.

Our earnings and cash flow may vary significantly due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments, or to permit us to pay dividends to our stockholders. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt or dividends. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as refinancing or restructuring our debt; selling assets; reducing or delaying capital investments; or seeking to raise additional capital. However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations or pay dividends. Our inability to generate sufficient cash flow to satisfy our debt obligations or pay dividends, or to obtain alternative financing, could materially and adversely affect our business, financial condition, results of operations and prospects.

Our ability to pay dividends to our stockholders is restricted by requirements under our Revolving Credit Facility.

Holders of our common stock are only entitled to receive such cash dividends as our Board, in its sole discretion, may declare out of funds legally available for such payments. We paid cash dividends of $58.0 million to our equity holders during the year ended December 31, 2023. We made cash distributions to our members totaling $36.0 million, $12.0 million and $6.0 million during the years ended December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, respectively. We cannot assure you that we will pay dividends in the future. Any future determination relating to the payment of dividends will be dependent on a variety of factors, including any limitations imposed by covenants in the Revolving Credit Facility and any debt agreements that we may enter into in the future. Under our Revolving Credit Facility, we are permitted to make cash distributions without limit to our equity holders if (i) no event of default or borrowing base deficiency (i.e., outstanding debt (including loans and letters of credit) exceeds the borrowing base) then exists or would result from such distribution and (ii) after giving effect to such distribution, (a) our total outstanding credit usage does not exceed 80% of the least of (the following collectively referred to as “Commitments”): (1) $500 million, (2) our then-effective borrowing base, and (3) the then-effective aggregate amount of our lenders’ commitments and (b) as of the date of such distribution, the EBITDAX Ratio does not exceed 1.50 to 1.00. If our EBITDAX Ratio does not exceed 2.25 to 1.00, and if our total outstanding credit usage does not exceed 80% of the Commitments, we may also make distributions if our distributable free cash flow (as defined under the Revolving Credit Facility) is greater than $0 and we have delivered a certificate to our lenders attesting to the foregoing. The summaries above do not purport to be complete and you are encouraged to read the Revolving Credit Facility, which is filed as an exhibit to this Annual Report on Form 10-K, for greater detail with respect to these provisions. As a consequence of these various limitations and restrictions, we may not be able to make, or may have to reduce or eliminate at any time, the payment of dividends on our common stock. If as a result, we are unable to pay dividends, investors may be forced to rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment. Any change in the level of our dividends or the suspension of the payment thereof could have a material adverse effect on the market price of our common stock. For additional information, please see —Risks Relating to Our Common Stock—Although we expect to continue to pay dividends, we cannot provide assurance that we will pay dividends on our common stock, and our indebtedness may limit our ability to pay dividends on our common stock.

Variable rate indebtedness could subject us to interest rate risk, which could cause our debt service obligations to increase significantly.

Our Revolving Credit Facility uses SOFR as a reference rate for borrowings. Borrowings under our Revolving Credit Facility may bear interest at variable rates and expose us to interest rate risk. If interest rates increase and we are unable to effectively hedge our interest rate risk, our debt service obligations on the variable rate indebtedness would increase even if the amount borrowed remained the same, and our net income and cash flows may decrease.

We may be adversely affected by developments in the SOFR market, changes in the methods by which SOFR is determined or the use of alternative reference rates.

In 2017, the U.K. Financial Conduct Authority announced that it intended to phase out LIBOR, and in 2021, it announced that all LIBOR settings will either cease to be provided by any administrator or no longer be representative immediately after December 31, 2021, in the case of one-week and two-month U.S. Dollar settings, and immediately after June 30, 2023, in the case of the remaining U.S. Dollar settings. The Alternative Refinance Rate Committee, a committee convened by the Federal Reserve that includes major market participants, has identified SOFR, a new index calculated by short-term repurchase agreements, backed by U.S. Treasury securities, as its preferred alternative rate for LIBOR in the U.S. Although SOFR appears to be the preferred replacement rate for U.S. Dollar LIBOR, it is unclear if other benchmarks may emerge. The consequences of these developments cannot be entirely predicted, and there can be no assurance that they will not result in financial market disruptions, significant increases in benchmark interest rates, substantially higher financing costs or a shortage of available debt financing, any of which could have an adverse effect on our business, financial position and results of operations, and our ability to pay dividends on our common stock.

Risks Relating to Legal and Regulatory Matters

Restrictions on our ability to acquire federal leases and more stringent regulations affecting our operators' exploration and production activities on federal lands may adversely impact our business.

Oil and gas exploration and production activities on federal lands are subject to federal requirements, orders, and lease conditions that regulate, among other matters, drilling and related operations on lands covered by federal leases and the calculation and disbursement of royalty payments to the federal government. For example, these regulations require the plugging and abandonment of wells and removal of production facilities by current and former operators, including corporate successors of former operators. These requirements may result in significant costs associated with the removal of tangible equipment and other restorative actions. Additionally, under certain circumstances, the BLM may require operations on federal leases to be suspended or terminated.

Oil and gas sector activity on federal lands have become subject to increasing regulatory scrutiny. We and our operators are affected by the adoption of new or more stringent laws, regulations and policy directives that, for economic, environmental protection or other policy reasons, could increase the operating costs of, or otherwise curtail exploration and development drilling for oil and natural gas. For example, in January 2021, President Biden signed an Executive Order directing the DOI to temporarily pause new oil and natural gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and natural gas leasing and permitting program. The order was subsequently blocked by a federal district court within 13 protesting states, including Montana and then lifted following negotiations pursuant to the passage of the IRA. The DOI's comprehensive review of the federal leasing program resulted in a reduction in the volume of onshore land held for lease and an increased royalty rate. Meanwhile, the DOI released a report on the federal oil and natural gas leasing program in November 2021 which included several recommendations for how to reform the program. Some of the report's recommendations, including an increased royalty rate, minimum bid limits, and a significant reduction in total available acreage, were required to be implemented as part of the IRA and have been subsequently incorporated in recent lease sales. While most of the Biden Administration's changes to federal lands regulations have focused on new leases, future regulatory efforts could shift focus to existing lease operations. For example, the BLM issued a proposed rule in November 2022 to reduce natural gas waste from venting, flaring, and leaks associated with exploration and production activities on federal and tribal lands.

The implementation of, and potential litigation in response to, the Biden Administration's Social Cost of GHGs ("SC-GHGs") metric may also impact future regulatory decision- and policy-making regarding oil and gas operations on federal lands. While the Fifth Circuit dismissed initial challenges to the Biden Administration's interim calculations of then-named interim Social Cost of Carbon values on standing grounds in February 2023, future litigation opposing federal agency application of the finalized SC-GHGs metric appears likely. In September 2023, the Biden Administration announced it would be directing federal agencies to incorporate SC-GHGs values in budgeting, procurement, and other agency decisions, including in environmental reviews, where appropriate. The ultimate impacts of these policy directives and ongoing and future litigation concerning BLM leases and the use of the SC-GHGs metric cannot be predicted at this time, but such could affect the character of new regulations on certain federal oil and gas leases or oil and gas infrastructure on federal lands, which in turn could adversely impact our operators' and our results of operations.

Additionally, oil and natural gas operations and related infrastructure projects on federal lands may be impacted by recent and ongoing revisions to the NEPA implementing regulations. NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs ("BIA"), to evaluate major agency actions, such as the issuance of permits that have 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. In January 2023, the CEQ released updated guidance for federal agency consideration of GHG emissions and climate change impacts in environmental assessments, which includes, among other recommendations, best practices for analyzing and communicating climate change effects.

Additionally, in July 2023 the CEQ proposed revisions to the NEPA implementing regulations that would expand requirements to analyze the cumulative effects of the project on climate change and consider any disproportionate impact of the project on communities with environmental justice concerns as well enhance certain project obligations for implementing environmental mitigation measures.

Operations on federal lands also face litigation risks. From time to time, legal challenges have been filed relating to federal leasing decisions, such as for failure to adequately assess the impact of any increase of GHG emissions resulting from increased production on federal lands. Historically, such challenges have sought the cancellation or pause of lease sales and obligations to redo environmental assessments. More recently, in April 2023 an environmental organization filed suit against the DOI, seeking to force the agency to develop and promulgate a regulation that would phase out all oil and gas development on federal lands by 2035.

Any of these administrative, legislative or judicial actions could adversely affect our financial condition and results of operations by restricting the lands available for development or by imposing additional and costly regulations. Additionally, depending on the results and mitigation recommendations presented in environment assessments or environmental impact statements required under NEPA, our operators and their service providers could incur added costs, and be subject to delays, limitations or prohibitions in the scope of crude oil and natural gas projects or performance of midstream services.

Potential future legislation or the imposition of new or increased taxes or fees may generally affect the taxation of oil and natural gas exploration and development companies and may adversely affect our operations and cash flows.

From time to time, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including certain key U.S. federal income tax provisions currently available to oil and natural gas companies. Such legislative changes have included, but not been limited to, (1) the repeal of the percentage depletion allowance for natural gas and oil properties, (2) the elimination of current deductions for intangible drilling and development costs, and (3) an extension of the amortization period for certain geological and geophysical expenditures. Although these provisions were largely unchanged in the most recent federal tax legislation, certain of these changes were considered for inclusion in the proposed "Build Back Better Act" and Congress could consider, and could include, some or all of these proposals as part of future tax reform legislation. Moreover, other more general features of any additional tax reform legislation, including changes to cost recovery rules, may be developed that also would change the taxation of oil and natural gas companies. It is unclear whether these or similar changes will be enacted in future legislation and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural gas development or increase costs, and any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Additionally, states in which we operate or own assets may impose new or increased taxes or fees on natural gas and oil extraction. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws or the imposition of new or increased taxes or fees on natural gas and oil extraction could adversely affect our operations and cash flows.

Our business involves the selling and shipping of oil by rail, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.

A portion of our oil production is transported to market centers by rail. Derailments in North America of trains transporting oil have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation by rail of flammable liquids. Any changes to existing laws and regulations, or promulgation of new laws and regulations, including any voluntary measures by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport 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. In addition, any derailment of oil involving oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities.

Our derivative activities expose us to potential regulatory risks.

The FTC, FERC and the CFTC have statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to derivative activities that we undertake with respect to oil, natural gas or other energy commodities, we are required to observe the market-related regulations enforced by these agencies. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations and financial condition.

Legislative and regulatory developments could have an adverse effect on our ability to use derivative instruments to reduce the effect of volatile oil and natural gas price, interest rate and other risks associated with our business.

The Dodd-Frank Act contains measures aimed at increasing the transparency and stability of the OTC derivatives market and preventing excessive speculation. On January 14, 2021, the CFTC published a final rule imposing position limits for certain futures and options contracts in various commodities (including oil and gas) and for swaps that are their economic equivalents, though certain types of derivative transactions are exempt from these limits, provided that such derivative transactions satisfy the CFTC's requirements for certain enumerated "bona fide" derivative transactions. The CFTC also has adopted final rules regarding aggregation of positions, under which a party that controls the trading of, or owns ten percent or more of the equity interests in, another party will have to aggregate the positions of the controlled or owned party with its own positions for purposes of determining compliance with position limits unless an exemption applies. The CFTC's aggregation rules are now in effect, although CFTC staff has granted relief until August 12, 2025 from various conditions and requirements in the final aggregation rules. These rules may affect both the size of the positions that we may hold and the ability or willingness of counterparties to trade with us, potentially increasing the costs of transactions. Moreover, such changes could materially reduce our access to derivative opportunities, which could adversely affect revenues or cash flow during periods of low oil and natural gas prices.

The CFTC also has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or to take steps to qualify for an exemption to such requirements. Although we believe we qualify for the end-user exception from the mandatory clearing requirements for swaps entered to mitigate its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use. If our swaps do not qualify for the commercial end-user exception, or if the cost of entering into uncleared swaps becomes prohibitive, we may be required to clear such transactions. The ultimate effect of these rules and any additional regulations on our business is uncertain.

The full impact of the Dodd-Frank Act and related regulatory requirements on our business will not be known until the regulations are fully implemented and the market for derivatives contracts has adjusted. In addition, it is possible that the current presidential administration could expand regulation of the OTC derivatives market and the entities that participate in that market through either the Dodd-Frank Act or the enactment of new legislation. Regulations issued under the Dodd-Frank Act (including any further regulations implemented thereunder) and any new legislation also may require certain counterparties to our derivative instruments to spin off some of their derivative activities to a separate entity, which may not be as creditworthy as the current counterparty. Such legislation and regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. We maintain an active hedging program related to oil and natural gas price risks. Such legislation and regulations could reduce trading positions and the market-making activities of our counterparties. If we reduce our use of derivatives as a result of legislation and regulations or any resulting changes in the derivatives markets, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures or to make payments on our debt obligations. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower oil and natural gas prices. Any of these consequences could have a material adverse effect on our business, our financial condition, and our results of operations.

Our business is subject to complex federal, state, and local laws, as well as other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our operational interests, as operated by our third-party operators, are regulated extensively at the federal, state, tribal and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Under these laws and regulations, our company (either directly or indirectly through our operators) could also be liable for personal injuries, property and natural resource damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of our business and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Part of the regulatory environment in which we do business includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities are subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our business and limit the quantity of natural gas we may produce and sell. A major risk inherent in the drilling plans in which we participate is the need for our operators to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on the development of our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, adversely affect our profitability. At this time, we cannot predict the effect of this increase on our results of operations. Furthermore, we may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and larger operating staff.

Failure to comply with federal, state and local environmental laws and regulations could result in substantial penalties and adversely affect our business.

All phases of the oil and natural gas business can present environmental risks and hazards and are subject to a variety of federal, state and municipal laws and regulations. Environmental laws and regulations, among other things, restrict and prohibit spills, releases or emissions of various substances produced in association with oil and natural gas operations, and require that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. There is risk of incurring significant environmental costs and liabilities as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to our business, and historical operations and waste disposal practices. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the imposition of injunctive relief. Additionally, our operators may be subject to operational restrictions or additional expenses regarding compliance with laws and regulations to protect endangered species, sensitive habitat, or other natural resources, which in turn could adversely impact our results of operations. See Part I. Items 1 and 2. Business and Properties—Regulation and Environmental Matters for additional discussion of the environmental laws and regulations that affect our business and the production activities of our operators.

Environmental legislation and regulations are evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge, regardless of whether we were responsible for the release or contamination and regardless of whether our operators met previous standards in the industry at the time they were conducted. In addition, claims for damages to persons, property or natural resources may result from environmental and other impacts of operations on our properties. The application of new or more stringent environmental laws and regulations to our business may cause us to curtail production or increase the costs of our production or development activities.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is used extensively by our third-party operators. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions though EPA has published permitting guidance and regulations covering certain hydraulic fracturing activities and investigated impacts of hydraulic fracturing on water resources. State regulation of hydraulic fracturing typically imposes permitting, public disclosure, and well construction requirements. For example, North Dakota requires operators to disclose the amount of water and chemicals used in hydraulic fracturing, subject to certain trade-secret exemptions. From time to time, there have also been various proposals to regulate hydraulic fracturing at the federal level and the Biden Administration could pursue regulatory initiatives to restrict hydraulic fracturing operations on federal lands. Any federal or state legislative or regulatory changes with respect to hydraulic fracturing could cause us to incur substantial compliance costs or result in operational delays, and the consequences of any failure to comply by us or our third-party operators could have a material adverse effect on our financial condition and results of operations.

In addition, in response to concerns relating to recent seismic events near underground disposal wells used for the disposal by injection of flowback and produced water or certain other oilfield fluids resulting from oil and natural gas activities (so-called “induced seismicity”), regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. States may, from time to time, develop and implement plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. These developments could result in additional regulation and restrictions on the use of injection wells by our operators to dispose of flowback and produced water and certain other oilfield fluids. Increased regulation and attention given to induced seismicity also could lead to greater opposition to, and litigation concerning, oil and natural gas activities utilizing injection wells for waste disposal. Until such pending or threatened legislation or regulations are finalized and implemented, it is not possible to estimate their impact on our business.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

The adoption of climate change legislation or regulations restricting emissions of carbon dioxide, methane, and other greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas we produce.

The threat of climate change continues to attract considerable attention in the United States and around the world. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, climate-related disclosure obligations, and regulations that directly limit GHG emissions from certain sources. Moreover, President Biden highlighted addressing climate change as a priority of his administration, issued several Executive Orders related to climate change, recommitted the United States to long-term international goals to reduce emissions, and continues to require the incorporation of climate change considerations into executive agency decision-making. As a result, our operations are subject to a series of regulatory, political, litigation, and financial risks associated with emissions of GHGs from the oil and natural gas industry.

In recent years the U.S. Congress has considered legislation to reduce emissions of GHGs, including methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas. While it presently appears unlikely that comprehensive climate change legislation will be passed by Congress in the near future, energy legislation and other regulatory initiatives have been and continue to be proposed that are relevant to GHG emissions issues. For example, the IRA, which appropriates significant federal funding for renewable energy initiatives and, for the first time ever, imposes a fee on GHG emissions from certain facilities, was signed into law in August 2022. The excess methane emissions fee provision of the IRA takes effect in 2024. The emissions fee and funding provisions of the law could increase operating costs within the oil and gas industry and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations. The EPA and the BLM also continue to propose, revise, and enforce regulations related to GHG emissions that increase operating costs for or otherwise restrict exploration and production activities. Several states have also implemented, of their own accord or in coordination with their neighbor states, regional initiatives and programs limiting, monitoring, or otherwise regulating GHG emissions. See Part I. Items 1 and 2. Business and Properties—Regulation and Environmental Matters, for additional discussion of regulatory matters affecting and resulting from risks related to climate change and GHGs.

At the international level, the United Nations ("UN") -sponsored Paris agreement ("Paris Agreement") requires member states to submit non-binding, individually determined reduction goals known as Nationally Determined Contributions every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. Various U.S. states and local governments have also publicly committed to furthering the goals of the Paris Agreement. The international community continues to meet annually to deliberate on global emissions reduction and climate-related initiatives. Most recently, at the 28th session of the Conference of the Parties ("COP28"), and agreement was made to transition "away from fossil fuels in energy systems in a just, orderly and equitable manner" and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for doing so was set. The full impact of these international agreements and initiatives on our business, including the impact of any actions taken to fulfill the United States' obligations thereunder, is uncertain at this time. The promulgation of new or more stringent regulations limiting or taxing the emission of GHGs, legislation restricting the production of oil and gas, or other climate-related policies having the affect of reducing the availability or attractiveness of fossil-fuel energy could reduce demand for the oil and gas our operators produce and sell and adversely impact our results of operations.

Increased regulatory scrutiny on emissions and related climate change matters has also led to increased litigation risks for fossil fuel companies. A number of states, municipalities and other plaintiffs have sought to bring suit against various oil and gas companies in state or federal court, alleging, among other things, that such energy companies created public nuisances by producing fuels that contributed to climate change and its effects, such as rising sea levels, and therefore, are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts. The Company is not currently a defendant in any of these lawsuits, but it could be named in actions in the future making similar allegations. Should the Company be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to causation or contribution to the asserted damage, or to other mitigating factors. Involvement in such a case could have adverse reputational impacts and an unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Regulatory requirements to reduce gas flaring and to further restrict emissions could have an adverse effect on our operations.

Wells in the Williston Basin of North Dakota, where we own significant oil and natural gas properties, produce natural gas as well as oil. Constraints in third party natural gas gathering and processing systems in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In 2014, the NDI Commission, North Dakota's chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Williston Basin. The NDI Commission requires operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. As of November 1, 2020, the enforceable gas capture percentage goal is

91%. Production caps or penalties may be imposed on certain wells that cannot meet the capture goals. It is possible that other states in which we operate, including Montana, will require gas capture plans or otherwise institute new regulatory requirements in the future to reduce flaring.

Gas capture requirements and other regulatory requirements, in North Dakota or our other locations, could increase our operators' operational costs and restrict production on our oil and natural gas properties, which could materially and adversely affect our financial condition, results of operations and cash flows. If our interpretation of the applicable regulations is incorrect, or if we receive a non-appealable order to pay royalty on past and future flared volumes in North Dakota, such royalty payments could materially and adversely affect our financial condition and cash flows.

Risks Relating to Tax Matters

If the Distribution does not qualify as a transaction that is tax-free for U.S. federal income tax purposes, Jefferies and holders of Jefferies common stock who received shares of our common stock in connection with the Spin-Off could be subject to significant tax liability.

In connection with the Spin-Off, Jefferies' received (1) a ruling from the IRS and (2) a tax opinion from legal counsel, each substantially to the effect that, subject to the limitations specified therein and the accuracy of and compliance with certain representations, warranties and covenants, the Distribution, together with certain related transactions, qualified as a tax-free "reorganization" for U.S. federal income tax purposes under Section 368(a)(1)(D) of the Code and the Distribution qualified as a tax-free distribution within the meaning of Section 355 of the Code.

Although the IRS ruling is generally binding on the IRS, the continuing validity of the IRS ruling is subject to the accuracy of the factual representations made in the ruling request. In addition, in rendering its tax opinion, legal counsel relied on (1) customary representations and covenants made by Jefferies and Vitesse and (2) specified assumptions, including an assumption regarding the completion of the Distribution and certain related transactions in the manner contemplated by the transaction agreements. If any of those representations, covenants or assumptions are inaccurate, the tax opinion may not be valid and the tax consequences of the Distribution and certain related transactions could differ from those described above. Notwithstanding the receipt of the IRS ruling and tax opinion, there can be no assurance that the IRS or a court will not take a contrary position and the consequences of the Distribution and certain related transactions to Jefferies and the holders of Jefferies common stock could be materially different from, and worse than, the U.S. federal income tax consequences described above.

If it were determined that the Distribution, together with certain related transactions, did not qualify as a tax-free "reorganization" within the meaning of Section 368(a)(1)(D) of the Code and the Distribution did not qualify as a distribution to which Section 355 of the Code applies, Jefferies would generally be subject to tax as if it sold the Vitesse common stock in a transaction taxable to Jefferies, which could result in a material tax liability. In addition, Jefferies shareholders who are U.S. holders would generally, for U.S. federal income tax purposes, be treated as receiving a distribution in an amount equal to the fair market value of our common stock received, which could result in a material tax liability.

We agreed to numerous restrictions to preserve the non-recognition treatment of the Distribution, which may reduce our strategic and operating flexibility.

We agreed in the Tax Matters Agreement to covenants and indemnification obligations that address compliance with Section 355(e) of the Code. These covenants and indemnification obligations may limit our ability to pursue strategic transactions or engage in new businesses or other transactions that may otherwise maximize the value of our business, and might discourage or delay a strategic transaction that our stockholders may consider favorable, including share repurchases, stock issuances, certain asset dispositions and other strategic transactions. To preserve the tax-free treatment of the Distribution, and in addition to our indemnity obligations described above, the Tax Matters Agreement restricts us, for the two-year period following the Distribution, except in specific circumstances, from: (1) entering into any transaction pursuant to which all or a specified portion of our stock would be acquired, whether by merger or otherwise, (2) issuing equity securities in a manner that could reasonably be expected to have adverse consequences under Section 355(e) of the Code, (3) repurchasing shares of our stock other than in certain open-market transactions, (4) ceasing to actively conduct certain of our businesses or (5) taking or failing to take any other action that prevents the Distribution and certain related transactions from qualifying as a transaction that is generally tax-free for U.S. federal income tax purposes under Sections 355 and 368(a)(1)(D) of the Code.

We could have an indemnification obligation to Jefferies in certain circumstances if the Distribution were determined not to qualify for tax-free treatment for U.S. federal tax purposes, or in certain other circumstances, which could materially adversely affect our business, financial condition and results of operations.

In connection with the Spin-Off, we entered into a Tax Matters Agreement with Jefferies. The terms of the Tax Matters Agreement require us to indemnify Jefferies and certain related parties for certain taxes and losses that (i) result primarily from, individually or in the aggregate, the breach of certain representations and warranties made by us (including in connection with the IRS ruling or the tax opinion regarding the tax treatment of the Distribution) or covenants made by us (applicable to actions or failures to act by us and our subsidiaries following the completion of the Distribution), (ii) are attributable to actions we take following the Distribution and result from the failure of the transfer of the Vitesse Energy equity interests to Vitesse, together with the Distribution, to qualify as (a) a reorganization described in Section 355(a) and Section 368(a)(1)(D) of the Code, (b) a transaction in which the stock distributed thereby is “qualified property” for purposes of Sections 355(c) and 361(c) of the Code, or (c) a transaction in which Jefferies, Vitesse and the holders of Jefferies common stock recognize no income or gain for U.S. federal income tax purposes pursuant to Sections 355, 361 and 1032 of the Code, including, as a result of the application of Section 355(e) of the Code to the Distribution as a result of a 50% or greater change in ownership as described below, or (iii) are attributable to taxes with respect to Vitesse Energy or Vitesse Oil for tax periods or portions thereof ending before the Distribution, including as may arise on audit.

Even if the Distribution were otherwise to qualify as a tax-free transaction under Section 368(a)(1)(D) and Section 355 of the Code, the Distribution would be taxable to Jefferies (but not to Jefferies’ shareholders) pursuant to Section 355(e) of the Code if there were a 50% or greater change in beneficial ownership of either Jefferies or Vitesse as part of a plan or series of related transactions that included the Distribution. For this purpose, any acquisitions of Jefferies or our common stock during the four-year period beginning on the date that begins two years before the date of the Distribution are presumed to be part of such a plan, although we or Jefferies may rebut that presumption. The U.S. federal income tax rules for determining whether there has been a 50% or greater change in beneficial ownership of Jefferies and Vitesse, and the period during which that change is measured, are complex and include the aggregation and attribution rules of Section 355(e)(4)(C) of the Code. The Distribution itself does not give rise to a change in beneficial ownership, and public trading of the stock of Jefferies or Vitesse by small stockholders does not give rise to a change in beneficial ownership, but many other transactions could do so. Such transactions may include (but are not limited to) acquisitions by Vitesse or Jefferies using its own stock, the merger or consolidation of Vitesse or Jefferies with or into another company, redemptions, recapitalizations, stock dividends, and sales or issuances of stock.

Taxable gain or loss on the sale of our common stock could be more or less than expected.

If a stockholder sells our common stock, the stockholder will recognize gain or loss equal to the difference between the amount realized and the holder’s tax basis in the shares of common stock sold. A stockholder’s basis in our common stock may be adjusted during the course of its holding for various reasons, including being lowered as a result of certain distributions on our common stock, to the extent such distributions exceed our current and accumulated earnings and profits. In such a case, such excess will be treated as a tax free return of capital and will reduce a stockholder’s tax basis in our common stock. Such reduction in basis, to the extent that it shall occur, will result in a corresponding increase in the amount of gain, or a corresponding decrease in the amount of loss, recognized by the stockholder upon the sale of our common stock.

The IRS Forms 1099-DIV that our stockholders receive from their brokers may over-report dividend income with respect to our common stock for U.S. federal income tax purposes, which may result in a stockholder’s overpayment of tax. In addition, failure to report dividend income in a manner consistent with the IRS Forms 1099-DIV may cause the IRS to assert audit adjustments to a stockholder’s U.S. federal income tax return. For non-U.S. holders of our common stock, brokers or other withholding agents may overwithhold taxes from dividends paid, in which case a stockholder generally would have to timely file a U.S. tax return or an appropriate claim for refund to claim a refund of the overwithheld taxes.

Distributions we pay with respect to our common stock will constitute “dividends” for U.S. federal income tax purposes only to the extent of our current and accumulated earnings and profits. Distributions we pay in excess of our earnings and profits will not be treated as “dividends” for U.S. federal income tax purposes; instead, they will be treated first as a tax-free return of capital to the extent of a stockholder’s tax basis in their common stock and then as capital gain realized on the sale or exchange of such stock. We may be unable to timely determine the portion of our distributions that is a “dividend” for U.S. federal income tax purposes, which may result in a stockholder’s overpayment of tax with respect to distribution amounts that should have been classified as a tax-free return of capital. In such a case, a stockholder generally would have to timely file an amended U.S. tax return or an appropriate claim for refund to obtain a refund of the overpaid tax.

For a U.S. holder of our common stock, the IRS Forms 1099-DIV received from brokers may not be consistent with our determination of the amount that constitutes a “dividend” for U.S. federal income tax purposes or a stockholder may receive a corrected IRS Form 1099-DIV (and may therefore need to file an amended U.S. federal, state or local income tax return). We will attempt to timely notify our stockholders of available information to assist with income tax reporting (such as posting the correct information on our website). However, the information that we provide to our stockholders may be inconsistent with the amounts reported by a broker on IRS Form 1099-DIV, and the IRS may disagree with any such information and may make audit adjustments to a stockholder’s tax return.

For a non-U.S. holder of our common stock, “dividends” for U.S. federal income tax purposes will be subject to withholding of U.S. federal income tax at a 30% rate (or such lower rate as may be specified by an applicable income tax treaty) unless the dividends are effectively connected with the conduct of a U.S. trade or business. In the event that we are unable to timely determine the portion of our distributions that constitute a “dividend” for U.S. federal income tax purposes, or a stockholder’s broker or withholding agent chooses to withhold taxes from distributions in a manner inconsistent with our determination of the amount that constitutes a “dividend” for such purposes, a stockholder’s broker or other withholding agent may overwithhold taxes from distributions paid. In such a case, a stockholder generally would have to timely file a U.S. tax return or an appropriate claim for refund in order to obtain a refund of the overwithheld tax.

Some stockholders might be deemed to have received a taxable distribution as a result of our repurchase of our own stock.

Under certain circumstances, where a corporation repurchases its own stock, certain stockholders whose stocks have not been redeemed might be deemed to have received a taxable distribution. We do not currently know if any repurchase of our stock under the Stock Repurchase Program or any other contemplated repurchase of our stocks would satisfy the circumstances under which such potential tax liability may arise. While we believe that the repurchase of our stock under the Stock Repurchase Program and any other possible contemplated repurchase of our stocks, even if it were to satisfy such circumstances, would be an "isolated redemption" which would not result in taxable income to the non-redeemed stockholders, we have not requested, nor do we intend to request, a ruling to that effect. The IRS may disagree with this position, and a successful challenge by the IRS may thus result in taxable income to such non-redeemed stockholders.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Risk Management and Strategy

The Company recognizes the importance of developing, implementing, and maintaining cybersecurity measures to safeguard our information and operational technologies and protect the confidentiality, integrity, and availability of our data. Our business is dependent upon our computer systems, devices, software and networks (operational and information technology) to collect, process and store the data necessary to conduct almost all aspects of our business, including the evaluation of acquisition and development opportunities, the monitoring and evaluation of our existing properties and the performance of and data from our operators and the recording and reporting of financial information.

Assessing, Identifying and Managing Material Cybersecurity Risks & Integrated Overall Risk Management. We have processes in place to assess, identify, manage, and address material cybersecurity threats and incidents. These include, among other things: annual and ongoing security awareness training for employees; mechanisms to detect and monitor unusual network activity; and containment and incident response tools. We regularly assess risks from cybersecurity and technology threats and monitor our information systems for potential vulnerabilities. We monitor issues that are internally discovered or externally reported that may affect our systems, and have processes to assess those issues for potential cybersecurity impact or risk.

The Company has integrated cybersecurity risk management into our broader risk management framework to promote a company-wide culture of cybersecurity risk management. This integration is designed to include cybersecurity considerations as part of our decision-making processes at every level. Our IT department seeks to continuously evaluate and address cybersecurity risks in alignment with our business objectives and operational needs and coordinates with our overall risk management framework.

In the event of a cybersecurity incident, we maintain an incident response plan. This plan sets forth immediate actions to mitigate the impact of cybersecurity incidents, including referring certain matters to the Company's Chief Executive Officer ("CEO") for additional evaluation and oversight, as well as long-term strategies for remediation and prevention of future cybersecurity incidents.

Engaging Third Parties on Cybersecurity Risk Management. Recognizing the complexity and evolving nature of cybersecurity threats, the Company engages with a range of third-party service providers, including cybersecurity assessors, and consultants, in evaluating and testing our cybersecurity risk management systems. This enables us to leverage knowledge and insights with the goal of aligning our cybersecurity strategies and processes with best practices for our industry and size. Accordingly, we engage third-party service providers for regular cybersecurity-related audits, threat assessments, and consultation on security enhancements.

Overseeing Third-Party Risk. Because we are aware of the risks associated with engaging third-party service providers, the Company has implemented processes designed to oversee and manage these risks. It is our policy to conduct security assessments of all third-party service providers before engagement and we aim to maintain ongoing monitoring for compliance with our cybersecurity standards. This monitoring includes regular assessments by our Director of Infrastructure and Cybersecurity.

Cybersecurity Threats. As of the date of this Annual Report on Form 10-K, though the Company and our service providers have experienced certain cybersecurity incidents, we are not aware of any previous cybersecurity incidents that have materially affected or are reasonably likely to materially affect the Company, including our operations or financial condition. We acknowledge that cybersecurity threats are continually evolving, and the possibility of future cybersecurity incidents remains. Despite the implementation of our cybersecurity processes, our security measures cannot guarantee that a significant cybersecurity attack will not occur. While we devote resources to our security measures designed to protect our systems and information, no security measure is infallible. See Item 1A. Risk Factors "Risk Factors Relating to Our Business—We depend on computer and telecommunications systems, and failures in our systems or cyber security threats, attacks or other disruptions could significantly disrupt our business operations." for additional information about the risks to our business associated with a breach or other compromise to our information and operational technology systems.

Governance

Board of Directors Oversight. The Board has overall responsibility for the oversight of risk management at Vitesse, which includes cybersecurity risks. The Board receives periodic briefings on cybersecurity matters, including key risks to the Company, recent developments, and risk mitigation activities from members of management, who are responsible for overseeing our cybersecurity program. In addition, the Board receives annual briefings from our Director of Infrastructure and Cybersecurity,on our cybersecurity program.Our internal auditor also reports to the Audit Committee on the internal controls and procedures that are implemented to assess and mitigate cybersecurity risk on an as needed basis.

Management's Role. Our cybersecurity risk assessment and management efforts are led by our Director of Infrastructure and Cybersecurity, who is responsible for implementing and overseeing processes for the monitoring of our information systems. This includes responsibility for the deployment of cybersecurity measures and system audits to identify potential cybersecurity vulnerabilities. Our IT Department, including our Director of Infrastructure and Cybersecurity, reports directly to our CEO. Our Director of Infrastructure and Cybersecurity has significant experience in the field of information technology and is an ISACA Certified Information Security Manager (CISM).

Item 3. Legal Proceedings

From time to time we are subject to legal, administrative and environmental proceedings before various courts, arbitration panels and governmental agencies concerning claims arising in the ordinary course of business. These proceedings include certain contract disputes, additional environmental reviews and investigations, audits and pending judicial matters. Based on our current knowledge, we believe that the amount or range of reasonably possible losses will not, either individually or in the aggregate, materially adversely affect our business, financial condition and results of operations.

The results of any litigation cannot be predicted with certainty, and an unfavorable resolution in any legal proceedings could materially affect our business, financial condition and results of operations. Regardless of the outcome, litigation can have an adverse impact on us because of defense and settlement costs, diversion of management resources and other factors.

Item 4. Mine Safety Disclosures

None.

PART II

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

Market Information

Our common stock trades on the New York Stock Exchange under the symbol “VTS.” The closing price for our common stock on February 15, 2024 was $22.16 per share.

Comparison Performance Chart

The following information in this Item 5 of this Annual Report on Form 10-K is not deemed to be “soliciting material” or to be “filed” with the SEC or subject to Regulation 14A or 14C under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) or to the liabilities of Section 18 of the Exchange Act, and will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent we specifically incorporate it by reference into such a filing.

The following graph compares the cumulative total stockholder return on our common stock since January 17, 2023 (VTS’s first trading day following the Spin-Off), and the cumulative total returns of Standard & Poor’s 500 Index (“S&P 500”) and the S&P Oil & Gas Exploration & Production Select Industry Index (“S&P O&G E&P”) for the same period. This graph tracks the performance of a $100 investment in our common stock and in each index (including reinvestment of all dividends) from January 17, 2023 to December 31, 2023.

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Authorized Capital Stock

The Company has authorized 95,000,000 shares of common stock, par value $0.01 per share and 5,000,000 shares of preferred stock, par value $0.01 per share.

Shares Outstanding

As of February 15, 2024, we had 29,453,975 shares of our common stock outstanding, held by approximately 1,188 stockholders of record. The number of record holders does not necessarily bear any relationship to the number of beneficial owners of our common stock.

Securities Authorized for Issuance Under Equity Compensation Plans

See the information incorporated by reference under Part III. Item 12. Security Ownership of Certain Beneficial Owners and Management regarding securities authorized for issuance under our equity compensation plans.

Recent Sales of Unregistered Securities

In connection with the Pre-Spin-Off Transactions, Vitesse Energy Finance and holders of vested Vitesse Energy MIUs (other than Messrs. Gerrity and Cree) transferred their respective equity interests in Vitesse Energy to Vitesse in exchange for 25,918,163 shares and 163,544 shares, respectively, of common stock of Vitesse. The transfers were consummated shortly before the

Distribution. Shares of Vitesse common stock were issued to Vitesse Energy Finance and such holders of vested Vitesse Energy MIUs as consideration for their respective ownership interests in Vitesse Energy pursuant to Section 4(a)(2) of the Securities Act.

In connection with the Pre-Spin-Off Transactions, Jefferies Capital Partners and Gerrity Bakken transferred their respective equity interests in Vitesse Oil to Vitesse in exchange for 1,976,213 shares and 144,099 shares, respectively, of common stock of Vitesse. The transfers were consummated concurrently with the transfer of Vitesse Energy to Vitesse and shortly before the Distribution. Shares of Vitesse common stock were issued to Jefferies Capital Partners and Gerrity Bakken as consideration for their respective ownership interests in Vitesse Oil pursuant to Section 4(a)(2) of the Securities Act.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Issuer Purchases of Equity Securities

In February 2023, our Board approved a Stock Repurchase Program authorizing the repurchase of up to $60 million of the Company's common stock. Under the Stock Repurchase Program, Vitesse may repurchase shares of its common stock from time to time in open market transactions or such other means as will comply with applicable rules, regulations and contractual limitations. Our Board may limit or terminate the Stock Repurchase Program at any time without prior notice. The extent to which the Company repurchases its shares of common stock, and the timing of such repurchases, will depend upon market conditions and other considerations as may be considered in the Company's sole discretion.

The table below sets forth the information with respect to purchases made by or on behalf of the Company, or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) of our common stock during the quarter ended December 31, 2023.

Period	Total Number of Shares Purchased[(1)]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[(1)]	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
October 1, 2023 to October 31, 2023	—	$ —	—	59.8 million
November 1, 2023 to November 30, 2023	—	—	—	59.8 million
December 1, 2023 to December 31, 2023	—	—	—	59.8 million
Total	—	$ —	—	$ 59.8 million

(1) In February 2023, our Board approved a Stock Repurchase Program authorizing the repurchase of up to $60 million of the Company's common stock.

In January 2024, 792,000 restricted stock units vested with the Company retaining 332,840 of the vested shares to fund employee tax withholding of $6.9 million with the retained shares subsequently retired by the Company. These retained and retired shares are not included in the above table because they do not constitute a repurchase of equity securities.

Dividend Policy

The timing, declaration, amount of and payment of any dividends will be within the discretion of our Board and will depend upon many factors, including our financial condition, earnings, capital requirements of our operating subsidiaries, covenants associated with certain of our debt service obligations, legal requirements or limitations, industry practice, and other factors deemed relevant by our Board. We paid cash dividends of $58.0 million to our equity holders during the year ended December 31, 2023. While we believe that our future cash flows from operations will be able to sustain the current level of dividends, there can be no guarantee that we will be able to pay dividends at current levels or at all or otherwise return capital to our stockholders in the future. We have not adopted, and do not expect to adopt, a separate written dividend policy. For factors that could affect our ability to pay dividends, see Part I. Item 1A. Risk Factors, including —Risks Relating to Our Common Stock—Although we expect to continue to pay dividends, we cannot provide assurance that we will pay dividends on our common stock, and our indebtedness may limit our ability to pay dividends on our common stock and–Risks Relating to Our Indebtedness—Our ability to pay dividends to our stockholders is restricted by requirements under our Revolving Credit Facility.

Item 6. Reserved

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

You should read the following discussion of our results of operations and financial condition together with our Audited Consolidated Financial Statements and the notes thereto included under the section entitled "Index to Financial Statements," as well as the discussion in Part I. Items 1 and 2. Business and Properties. This discussion contains forward-looking statements that involve risks and uncertainties. The forward-looking statements are not historical facts, but rather are based on current expectations, estimates, assumptions and projections about the oil and natural gas industry and our business and financial results. Our actual results could differ materially from the results contemplated by these forward-looking statements due to a number of factors, including those discussed in Part I. Item 1A. Risk Factors and "Cautionary Statement Concerning Forward-Looking Statements."

Executive Overview

Our business strategy is focused on creating long-term stockholder value through the profitable acquisition, development and production of oil and natural gas assets at attractive rates of return, while maintaining a strong balance sheet and distributing a meaningful dividend to our stockholders. We invest in non-operated minority working and mineral interests in oil and natural gas properties with our core area of focus in the Williston Basin of North Dakota and Montana. We also have interests in wells in the Denver-Julesburg Basin located in Colorado and Wyoming and the Powder River Basin located in Wyoming. As of December 31, 2023, we had a working interest in 5,734 gross (157.5 net) productive wells and 224 gross (6.7 net) wells that were being drilled or completed, and an additional 363 gross (9.9 net) wells that had been permitted for development by our operators. Our estimated proved reserves as of December 31, 2023 were 40,595 MBoe (68% oil) and our average production was 11,889 Boe per day during the year ended December 31, 2023.

Our financial and operating performance for the year ended December 31, 2023 included the following:

- Total revenue of $233.9 million.
- Cash flows from operations of $141.9 million.
- Net loss of $19.7 million.
- Proved reserves of 40.6 MMBoe and $682.1 million PV-10 value at December 31, 2023, as estimated by our third-party reserve engineers using SEC guidelines.
- Total debt of $81.0 million at December 31, 2023.
- Paid $58.0 million in dividends to our equity holders.

See Part II. Item 7. Management Discussion and Analysis of Financial Condition and Results of Operations—Non-GAAP Financial Information for additional information about PV-10.

Industry Trends Impacting Our Business

Commodity prices are a significant factor impacting our acquisition and divestiture strategy, as well as the decisions of our operators in conducting their operations. Prices for oil and natural gas can be highly volatile. For instance, the COVID-19 pandemic and efforts to mitigate the spread of the disease, combined with OPEC actions in early 2020, led to spot and future prices of oil and natural gas falling to historic lows during the second quarter of 2020 and remaining depressed through much of 2020. Oil and gas operators responded by significantly decreasing drilling and completion activity, and by shutting in or curtailing production from a significant number of producing wells. Commodity prices, however, quickly reached pre-pandemic levels in the second half of 2021, and during 2022 increased further, in part as a result of the Russian invasion of Ukraine in combination with ongoing oil production limits from OPEC. In November 2023, certain members of OPEC and Russia and certain of its other allies ("OPEC+") agreed to voluntary production/ export cuts of 2.2 million bpd for the first quarter of 2024 (subject to extension) from the 2024 required production levels. These voluntary cuts are in addition to (i) a production cut of 2 million bpd agreed to by the alliance in October 2022 and (ii) voluntary cuts by certain members of OPEC+ of 1.66 million bpd announced in April 2023 and subsequently extended through the end of 2024. In addition, while the impact of the ongoing conflicts between Russia and Ukraine and in the Middle East remain uncertain, these conflicts may have further global economic consequences, including disruptions of the global energy markets, inflation and supply chain constraints.

As a result of such commodity price volatility, which we expect to continue throughout 2024, our earnings and operating cash flows can vary substantially. While we do hedge a substantial portion of our production, we are still significantly subject to movements in commodity prices. Such volatility can make it difficult to predict future effects on our financial results and the decisions of our operators. Factors that we expect will continue to impact commodity prices include product demand connected with global economic conditions, inflationary factors, industry production and inventory levels, the United States Department of Energy's future planned repurchases (or additional possible releases) of oil from the strategic petroleum reserve, technology advancements, production quotas or other actions imposed by OPEC countries, actions of regulators, and regional supply interruptions or fears thereof that may be caused by military conflicts (including invasion), civil unrest, pandemic or political uncertainty. Any of the foregoing can have a substantial impact on the prices of oil and natural gas, which in turn impacts the decision of our operators to drill and extract resources. Despite such commodity price volatility, we expect that our cash flow from operations and borrowing availability under our Revolving Credit Facility will allow us to meet our liquidity needs for the next twelve months.

Source of Our Revenues

We derive our revenues from the sale of oil and natural gas produced from our properties. Revenues are a function of the volume produced, the prevailing market price at the time of sale, oil quality, Btu content and transportation costs to market. We use derivative instruments to hedge future sales prices on a substantial, but varying, portion of our oil production. We have not hedged natural gas production since March 2022 due to the mismatch between our operators' pricing formulas and settlement mechanics on natural gas hedges. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements.

Principal Components of Our Cost Structure

Commodity price differentials. The price differential between our wellhead price for oil and the WTI benchmark price is primarily driven by the cost to transport oil via pipeline, train or truck to refineries. The price differential between our wellhead price for natural gas and the NYMEX benchmark price is primarily driven by Btu content along with gathering, processing and transportation costs.

Gain (loss) on commodity derivatives, net. We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the prices of oil and gas. Gain (loss) on commodity derivatives, net is comprised of (1) cash gains and losses we recognize on settled commodity derivatives during the period, and (2) non-cash mark-to-market gains and losses we incur on commodity derivative instruments outstanding at period-end.

Lease operating expenses. Lease operating expenses are costs incurred to bring oil and natural gas out of the ground and to market, together with the costs incurred to maintain our producing properties. Such costs include field personnel compensation, saltwater disposal, utilities, maintenance, repairs and servicing expenses related to our oil and natural gas properties.

Production taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at market prices (not hedged prices) or at fixed rates established by federal, state or local taxing authorities. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

Depletion, depreciation, amortization, and accretion. Depletion, depreciation, amortization, and accretion ("DD&A") includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas properties. As a successful efforts company, costs associated with the acquisition, drilling, and equipping of successful exploratory wells and costs of successful and unsuccessful development wells are capitalized. Accretion expense relates to the passage of time of our asset retirement obligations.

General and administrative expenses. General and administrative expenses include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our acquisition and development operations, franchise taxes, audit and other professional fees and legal compliance. For fiscal 2022 and 2023, general and administrative expenses included non-recurring costs related to the Spin-Off.

Interest expense. We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings under our Revolving Credit Facility and prior to the Spin-Off, under the Prior Revolving Credit Facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We do not capitalize any portion of the interest paid on applicable borrowings. We include the amortization of deferred financing costs, commitment fees and annual agency fees as interest expense.

Impairment expense. Under the successful efforts method of accounting, we review our oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Whenever we conclude the carrying value may not be recoverable, we estimate the expected undiscounted future net cash flows of our oil and natural gas properties using proved and risked probable and possible reserves based on our development plans and best estimate of future production, commodity pricing, reserve risking, gathering, processing and transportation deductions, production tax rates, lease operating expenses and future development costs. We compare such undiscounted future net cash flows to the carrying amount of the oil and natural gas properties in each depletion pool to determine if the carrying amount is recoverable. If the undiscounted future net cash flows exceed the carrying amount of the aggregated oil and natural gas properties, no impairment is recorded. If the carrying amount of the oil and natural gas properties exceeds the undiscounted future net cash flows, we will record an impairment expense to reduce the carrying value to fair value as of the balance sheet date. The factors used to determine fair value may include, but are not limited to, recent sales prices of comparable properties, indications from marketing activities, the present value of future revenues, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the projected cash flows.

Income tax expense. Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. Vitesse Energy, our Predecessor, was a limited liability company. Accordingly, no provision for income taxes was recorded, as the income, deductions, expenses, and credits of the Predecessor were reported on the income tax returns of it's members.

Selected Factors That Affect Our Operating Results

Our revenues, cash flows from operations and future growth depend substantially upon:

- the timing and success of drilling and production activities by our operating partners;
- the prices and the supply and demand for oil, natural gas and NGLs;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments;
- our ability to continue to identify and acquire high-quality acreage and drilling opportunities; and
- the level of our operating expenses.

In addition to the factors that affect companies in our industry generally, the location of substantially all of our acreage and wells in the Williston, Denver-Julesburg and Powder River Basins subjects our operating results to factors specific to these regions. These factors include the potential adverse impact of weather on drilling, production and transportation activities, particularly during the winter and spring months, as well as infrastructure limitations, transportation capacity, regulatory matters and other factors that may specifically affect one or more of these regions.

Market Conditions

The price of oil can vary depending on the market in which it is sold and the means of transportation used to transport the oil to market, particularly in the Williston Basin where a substantial majority of our revenues are derived. Additional pipeline infrastructure has increased takeaway capacity in the Williston Basin which has improved wellhead values in the region.

The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Because our oil and gas revenues are heavily weighted toward oil, we are more significantly impacted by changes in oil prices than by changes in the price of natural gas. World-wide supply in terms of output, especially production from properties within the United States, the production quota set by OPEC, the conflicts in Ukraine and in the Middle East and the strength of the U.S. dollar can adversely impact oil prices.

The price at which our oil production is sold typically reflects a discount to the WTI benchmark price. The price at which our natural gas production is sold may reflect either a discount or premium to the Henry Hub benchmark price. Thus, our operating results are also affected by changes in the oil price differentials between the applicable benchmark and the sales prices we receive for our oil production. Our oil price differential to the weighted average WTI benchmark price during the year ended December 31, 2023 was negative $4.19 per Bbl, as compared to a negative $3.39 per Bbl during the year ended December 31, 2022, primarily due to less favorable local market pricing, including gathering and transportation costs, as compared to the benchmark price. Our net realized natural gas price during the year ended December 31, 2023 was $1.88 per Mcf, representing a 74% realization relative to average Henry Hub pricing, compared to a net realized natural gas price of $6.64 per Mcf during the year ended December 31, 2022, representing a 103% realization relative to average Henry Hub pricing. Fluctuations in our natural gas price differentials and realizations are due to several factors such as NGL value net of processing costs, gathering, and transportation costs, takeaway capacity relative to production levels, regional storage capacity, seasonal demand for heating fuel and seasonal refinery maintenance temporarily depressing demand. The exact impact of each of these items is difficult to quantify as each of our operators pass through these costs in a different manner.

Historically, commodity prices have been volatile and we expect the volatility to continue in the future. Factors impacting the future oil supply balance include world-wide demand for oil, as well as the growth in domestic oil production.

Prices for various quantities of oil, natural gas and NGLs significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the periods presented.

Average NYMEX Prices [1]	YEAR ENDED DECEMBER 31, 2023	YEAR ENDED DECEMBER 31, 2022	YEAR ENDED DECEMBER 31, 2021	YEAR ENDED NOVEMBER 30, 2021
WTI Oil (per Bbl)	$ 77.58	$ 94.90	$ 68.14	$ 65.97
Natural Gas (per MMBtu)	2.53	6.45	3.89	3.79

(1) Based on a simple average of daily NYMEX closing prices.

The average calendar 2023 WTI oil price was $77.58 per Bbl or 18% lower than the average WTI price per Bbl in calendar 2022. Our settled derivatives increased our realized oil price per Bbl by $0.40 in calendar 2023 and decreased our realized oil price per Bbl by $18.07 in calendar 2022. Our average 2023 realized oil price per Bbl after reflecting settled derivatives was $73.99 compared to $72.66 in 2022. The average calendar 2023 NYMEX natural gas price was $2.53 per MMBtu, or 61% lower than the average NYMEX price per MMBtu in calendar 2022. We had no gas price derivatives in place in calendar 2023 and our settled derivatives decreased our realized natural gas price per Mcf by $0.08 in 2022. Our 2023 realized natural gas price per Mcf after reflecting settled derivatives was $1.88 compared to $6.56 in 2022, which was primarily driven by lower NYMEX pricing for natural gas and gas realization.

We employ a hedging program that mitigates the risk associated with fluctuations in commodity prices. For detailed information on our commodity hedging program, see Part II. Item 7A. Quantitative and Qualitative Disclosures about Market Risk and Notes to Consolidated Financial Statements—Note 6—Derivative Instruments.

Another significant factor affecting our operating results is drilling costs. The cost of drilling wells can vary significantly, driven in part by volatility in commodity prices that can substantially impact the level of drilling activity. Generally, higher oil prices have led to increased drilling activity, with the increased demand for drilling and completion services driving these costs higher. Lower oil prices have generally had the opposite effect. In addition, individual components of the cost can vary depending on numerous factors such as the length of the horizontal lateral, the number of fracture stimulation stages, and the type and amount of proppant.

Results of Operations

Change in Estimate that is Inseparable from a Change in Accounting Principle

Effective January 1, 2023, the Company changed its method of recording gathering and transportation (“GT”) costs. Under the current method, GT costs are presented as a deduction to oil and gas revenue, following how these items are reported to us by operators. Prior to January 1, 2023, under our previous method, we determined the GT costs that were reported within production expense versus revenue deductions based on our best estimates using information from all our operators in aggregate. Although the change does not have a material impact to the financial statements the change in methodology has been applied on a retrospective basis to the prior periods presented in order to conform to the current period presentation. This change results in a reclassification within the statements of operations and has no balance sheet impact, nor does it impact net income, operating income, the gross margin we generate from our interests in oil and gas properties, or cash flows for any period.

Year Ended December 31, 2023 Compared with Year Ended December 31, 2022

The following table sets forth selected operating data for the periods indicated.

	YEAR ENDED DECEMBER 31,		INCREASE (DECREASE)	
($ in thousands, except per unit data)	**2023**	**2022**	**AMOUNT**	**PERCENT**
Operating Results:				
Revenue				
Oil	$ 218,396	$ 233,622	$ (15,226)	(7%)
Natural gas	15,509	48,268	(32,759)	(68%)
Total revenue	$ 233,905	$ 281,890	$ (47,985)	(17%)
Operating Expenses				
Lease operating expense	$ 39,514	$ 31,133	$ 8,381	27%
Production taxes	21,625	24,092	(2,467)	(10%)
General and administrative	23,934	19,833	4,101	21%
Depletion, depreciation, amortization, and accretion	81,745	63,732	18,013	28%
Equity-based compensation	32,233	(10,766)	42,999	*nm
Interest Expense	$ 5,276	$ 4,153	$ 1,123	27%
Income Tax Expense	$ 61,946	$ —	$ 61,946	*nm
Commodity Derivative Gain (Loss)	$ 12,484	$ (30,830)	$ 43,314	140%
Production Data:				
Oil (MBbls)	2,968	2,575	393	15%
Natural gas (MMcf)	8,232	7,274	958	13%
Combined volumes (MBoe)	4,340	3,787	553	15%
Daily combined volumes (Boe/d)	11,889	10,376	1,513	15%
Average Realized Prices before Hedging:				
Oil (per Bbl)	$ 73.59	$ 90.73	$ (17.14)	(19%)
Natural gas (per Mcf)	1.88	6.64	(4.76)	(72%)
Combined (per Boe)	53.90	74.43	(20.53)	(28%)
Average Realized Prices with Hedging:				
Oil (per Bbl)	$ 73.99	$ 72.66	$ 1.33	2%
Natural gas (per Mcf)	1.88	6.56	(4.68)	(71%)
Combined (per Boe)	54.17	61.99	(7.82)	(13%)
Average Costs (per Boe):				
Lease operating expense	$ 9.11	$ 8.22	$ 0.89	11%
Production taxes	4.98	6.36	(1.38)	(22%)
General and administrative	5.52	5.24	0.28	5%
Depletion, depreciation, amortization, and accretion	18.84	16.83	2.01	12%

* Not meaningful

Oil and Natural Gas Revenue and Volumes. Oil and natural gas revenue decreased to $233.9 million for the year ended December 31, 2023 from $281.9 million for the year ended December 31, 2022. The decrease in oil and natural gas revenue was due to a 28% decrease in the average realized prices per Boe before hedging, and was partially offset by a 15% increase in production volumes for the year ended December 31, 2023. The decrease in average realized prices per Boe before hedging decreased oil and natural gas revenue by approximately $77.7 million, while the increase in production volumes increased oil and natural gas revenue by approximately $29.8 million.

The decreases in realized oil and natural gas prices were primarily due to lower benchmark commodity prices in the year ended December 31, 2023 as compared to the year ended December 31, 2022, as well as increased differentials. Our oil price differential to the weighted average benchmark price during the year ended December 31, 2023 was negative $4.19 per Bbl, as compared to a negative $3.39 per Bbl during the year ended December 31, 2022, primarily due to less favorable local market pricing as compared to the benchmark price. Our net realized natural gas price during the year ended December 31, 2023 was $1.88 per Mcf, representing a 74% realization relative to the weighted average NYMEX natural gas price, compared to a net realized natural gas price of $6.64 per Mcf during the year ended December 31, 2022, representing a 103% realization relative to the weighted average NYMEX natural gas price. Fluctuations in our natural gas price differentials and realizations are due to several factors such as NGL value net of processing costs, gathering and transportation fees, takeaway capacity relative to production levels, regional storage capacity, seasonal demand for heating fuel and seasonal refinery maintenance temporarily depressing demand. The exact impact of each of these items is difficult to quantify as each of our operators pass through these costs in a different manner.

Lease Operating Expense. Lease operating expense increased to $9.11 per Boe for the year ended December 31, 2023 from $8.22 per Boe for the year ended December 31, 2022. The increase per Boe for the year ended December 31, 2023 compared with the year ended December 31, 2022 was related to increased workover operations and higher service costs. The increased workover costs were responsible for approximately $0.48/Boe of the increase and should result in increased production when these wells return to production.

Production Tax Expense. Total production taxes decreased to $21.6 million for the year ended December 31, 2023 from $24.1 million for the year ended December 31, 2022, primarily due to the decrease in oil and gas revenue in 2023. Production taxes are primarily based on oil revenue and natural gas production, excluding gains and losses associated with hedging activities. Production taxes as a percentage of oil and natural gas sales before hedging adjustments were 9.2% and 8.5% for the years ended December 31, 2023 and 2022, respectively. The increase in the production tax rate for the year ended December 31, 2023 was primarily due to a higher ratio of oil revenue to total revenue, since oil revenue is taxed at a higher rate than gas revenue.

General and Administrative Expense. General and administrative expense increased to $23.9 million for the year ended December 31, 2023 from $19.8 million for the year ended December 31, 2022. General and administrative expense on a per Boe basis increased to $5.52 for the year ended December 31, 2023 from $5.24 for the year ended December 31, 2022. Costs related to the Spin -Off are included in both periods. Excluding costs related to the Spin-Off, the per Boe rate for the years ended December 31, 2023 and 2022 would have been $3.94 and $3.15, respectively. The increase in general and administrative expense per Boe, excluding the Spin-Off costs, was primarily due to higher costs associated with being a public company.

DD&A. DD&A increased to $81.7 million for the year ended December 31, 2023 compared with $63.7 million for the year ended December 31, 2022. The increase of $18.0 million or 28% was the result of a 15% increase in production and a 12% increase in the DD&A rate for the year ended December 31, 2023 compared with the year ended December 31, 2022. The increase in production accounted for a $10.4 million increase in DD&A expense while the increase in the DD&A rate accounted for a $7.6 million increase in DD&A expense.

For the year ended December 31, 2023, the relationship of capital expenditures, proved reserves and production from certain producing fields yielded a depletion rate (excluding depreciation, amortization and accretion) of $18.68 per Boe compared with $16.71 per Boe for the year ended December 31, 2022. The increase in the depletion rate was driven by a combination of decreased oil and natural gas reserves related to the lower oil and natural gas prices and the impact of acquisitions in the year ended December 31, 2023.

Equity-based Compensation. The Company's long-term incentive plan ("LTIP") provides for the granting of various forms of equity-based awards, including restricted stock units, performance units, stock options, stock appreciation rights, restricted stock, cash awards and other stock-based awards to employees, directors and consultants of the Company. Through December 31, 2023, the Company granted 3,152,247 restricted stock units, net of forfeitures, to employees and directors at a weighted-average grant date fair value of $14.99 per share. For restricted stock units, the Company recognizes the grant date fair-value of stock-based compensation awards expected to vest over the requisite service period as stock-based compensation expense on a straight-line basis except when provisions are present that accelerate vesting. Retirement vesting provisions in some of the awards resulted in 1,863,000 restricted stock units being expensed upon award. Equity-based compensation expense was $32.2 million for the year ended December 31, 2023.

Unit-based compensation expense was previously recorded by our Predecessor for in-substance call options granted to the founding members of management which are classified as liabilities and recorded at estimated fair value at each period end. Unit-based compensation expense was also recognized for management incentive units granted to other employees which are classified as liabilities until the holder has borne the risk of unit ownership. Unit-based compensation expense was recorded as these units vested and expense or contra-expense was recognized as the estimated fair value of the liability changed with market conditions. Unit-based compensation contra-expense was $10.8 million for the year ended December 31, 2022.

Interest Expense. Interest expense increased to $5.3 million for the year ended December 31, 2023 from $4.2 million for the year ended December 31, 2022. The increase for the year ended December 31, 2023 was due to a higher SOFR interest rate in the year ended December 31, 2023 despite a lower average outstanding balance on our Revolving Credit Facility during the year ended December 31, 2023 compared to 2022. The higher interest rate was due to increases to the federal funds rate by the Federal Reserve throughout 2022 and 2023.

Commodity Derivative Gain (Loss). The net commodity derivative gain was $12.5 million for the year ended December 31, 2023 compared with a loss of $30.8 million for the year ended December 31, 2022. Gain (Loss) on Commodity Derivatives is comprised of (1) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (2) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

The mark-to-market fair value of the unsettled commodity derivative instruments will generally be inversely related to the price movement of the underlying commodity. If commodity price trends reverse from period to period, prior unrealized gains may become unrealized losses and vice versa. These unrealized gains and losses will impact our net income in the period reported. The mark-to-market fair value can create non-cash volatility in our reported earnings during periods of commodity price volatility. We have experienced such volatility in the past and are likely to experience it in the future. Gains on our derivatives generally indicate lower oil revenues in the future while losses indicate higher future oil revenues.

The table below summarizes our commodity derivative gains and losses that were recorded in the periods presented.

	YEAR END DECEMBER 31,	
(in thousands)	**2023**	**2022**
Realized gain (loss) on commodity derivatives [(1)]	$ 1,166	$ (47,124)
Unrealized gain (loss) on commodity derivatives [(1)]	11,318	$ 16,294
Total commodity derivative gain (loss)	$ 12,484	$ (30,830)

(1) Realized and unrealized gains and losses on commodity derivatives are presented herein as separate line items but are combined for a total commodity derivative gain (loss) in the consolidated statements of operations included in this Annual Report on Form 10-K. Management believes the separate presentation of the realized and unrealized commodity derivative gains and losses is useful because the realized cash settlement portion provides a better understanding of our hedge position.

In 2023, approximately 49% of our oil volumes and none of our natural gas volumes were covered by financial hedges, which resulted in a realized gain on oil derivatives of $1.2 million. In 2022, approximately 55% of our oil volumes and 6% of our natural gas volumes were covered by financial hedges, which resulted in a realized loss on oil derivatives of $46.5 million and a realized loss on natural gas derivatives of $0.6 million after settlements.

At December 31, 2023, all of our derivative contracts were recorded at their fair value, which was a net asset of $11.1 million, an increase of $11.3 million from the $0.2 million net liability recorded as of December 31, 2022. The increase was due to changes to forward commodity prices relative to prices on our open commodity derivative contracts and new contracts entered into in the year ended December 31, 2023.

Income Tax Expense. We recorded income tax expense of $61.9 million for the year ended December 31, 2023 related to federal and state income taxes, including $44.1 million recorded at Spin-Off as discussed below. The provision for income taxes for the year ended December 31, 2023 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income primarily due to §162(m) limitations on certain covered employee compensation and state income taxes. No income tax expense was recorded for the year ended December 31, 2022 because the Predecessor was treated as a nontaxable partnership for income tax purposes for that period.

During the year ended December 31, 2023, the Predecessor was contributed into Vitesse resulting in a change in tax status and the recording of a $44.1 million deferred tax liability related to the temporary difference between the tax and GAAP basis of the assets of the Predecessor and an offsetting charge to income tax expense.

Change in Fiscal Year End

On November 30, 2021, our Board and the Board of Managers of our Predecessor approved a change in our fiscal year end and that of our Predecessor from November 30 to December 31. As a result, Vitesse Energy's 2022 fiscal year began on January 1, 2022 and ended on December 31, 2022 and there was a transition period from December 1, 2021 to December 31, 2021 (the "Transition Period"). For the purposes of this discussion and analysis we have presented the income statement for the year ended December 31, 2021 in order to provide a comparison to the year ended December 31, 2022. The income statement for the year ended December 31, 2021 was derived as follows:

	YEAR ENDED NOVEMBER 30, 2021	PLUS: MONTH ENDED DECEMBER 31, 2021 (TRANSITION PERIOD)	LESS: MONTH ENDED DECEMBER 31, 2020	YEAR ENDED DECEMBER 31, 2021
(in thousands)				
Oil	$ 144,818	$ 14,797	$ 8,052	$ 151,563
Natural gas	23,017	1,669	214	24,472
Total revenue	167,835	16,466	8,266	176,035
Operating Expenses				
Lease operating expense	26,567	2,272	1,689	27,150
Production taxes	14,535	1,340	863	15,012
General and administrative	10,581	950	793	10,738
Depletion, depreciation, amortization, and accretion	60,846	5,417	5,380	60,883
Equity-based compensation	1,409	2,628	—	4,037
Total operating expenses	113,938	12,607	8,725	117,820
Operating Income (Loss)	53,897	3,859	(459)	58,215
Other (Expense) Income				
Commodity derivative (loss) gain, net	(32,590)	(10,982)	(3,681)	(39,891)
Interest expense	(3,207)	(237)	(319)	(3,125)
Other income	14	1	1	14
Total other (expense) income	(35,783)	(11,218)	(3,999)	(43,002)
Net Income (Loss)	$ 18,114	$ (7,359)	$ (4,458)	$ 15,213

Year Ended December 31, 2022 Compared with Year Ended December 31, 2021

The following table sets forth selected operating data for the periods indicated.

	YEAR ENDED DECEMBER 31,		INCREASE (DECREASE)	
(in thousands, except per unit data)	2022	2021	AMOUNT	PERCENT
Operating Results:				
Revenue				
Oil	$ 233,622	$ 151,563	$ 82,059	54%
Natural gas	48,268	24,472	23,796	97%
Total revenue	$ 281,890	$ 176,035	$ 105,855	60%
Operating Expenses				
Lease operating expense	$ 31,133	$ 27,150	$ 3,983	15%
Production taxes	24,092	15,012	9,080	60%
General and administrative	19,833	10,738	9,095	85%
Depletion, depreciation, amortization, and accretion	63,732	60,883	2,849	5%
Equity-based compensation	(10,766)	4,037	(14,803)	*nm
Interest Expense	$ 4,153	$ 3,125	$ 1,028	33%
Commodity Derivative Gain (Loss)	$ (30,830)	$ (39,891)	$ 9,061	23%
Production Data:				
Oil (MBbls)	2,575	2,447	128	5%
Natural gas (MMcf)	7,274	7,084	190	3%
Combined volumes (MBoe)	3,787	3,627	160	4%
Daily combined volumes (Boe/d)	10,376	9,937	439	4%
Average Realized Prices before Hedging:				
Oil (per Bbl)	$ 90.73	$ 61.94	$ 28.79	46%
Natural gas (per Mcf)	6.64	3.45	3.19	92%
Combined (per Boe)	74.43	48.53	25.90	53%
Average Realized Prices with Hedging:				
Oil (per Bbl)	$ 72.66	$ 55.36	$ 17.30	31%
Natural gas (per Mcf)	6.56	3.34	3.22	96%
Combined (per Boe)	61.99	43.87	18.12	41%
Average Costs (per Boe):				
Lease operating expense	$ 8.22	$ 7.49	$ 0.73	10%
Production taxes	6.36	4.14	2.22	54%
General and administrative	5.24	2.96	2.28	77%
Depletion, depreciation, amortization, and accretion	16.83	16.79	0.04	—%

* Not meaningful

Oil and Natural Gas Revenue and Volumes. Oil and natural gas revenue increased to $281.9 million for the year ended December 31, 2022 from $176.0 million for the year ended December 31, 2021. The increase in oil and natural gas revenue was due to a 53% increase in the average realized prices per Boe before hedging, along with a 4% increase in production volumes for the year ended December 31, 2022. The increase in average realized prices per Boe before hedging increased oil and natural gas revenue by approximately $93.9 million, while the increase in production volumes increased oil and natural gas revenue by approximately $12.0 million.

Our oil price differential to the weighted average WTI benchmark price during the year ended December 31, 2022 was negative $3.39 per Bbl as compared to a negative $6.11 per Bbl during the year ended December 31, 2021, primarily due to favorable local market pricing as compared to the weighted average benchmark price. Our net realized natural gas price during the year ended December 31, 2022 was $6.56 per Mcf, representing a 103% realization relative to the weighted average NYMEX natural gas price, compared to a net realized natural gas price of $3.34 per Mcf during the year ended December 31, 2021, representing a 92% realization relative to weighted average NYMEX natural gas price. Fluctuations in our price differentials and realizations are due to several factors such as NGL value net of processing costs, gathering and transportation fees, takeaway capacity relative to production levels, regional storage capacity, seasonal demand for heating fuel and seasonal refinery maintenance temporarily depressing demand. The exact impact of each of these items is difficult to quantify as each of our operators pass through these costs in a different manner.

Lease Operating Expense. Lease operating expense increased to $8.22 per Boe for the year ended December 31, 2022 from $7.49 per Boe for the year ended December 31, 2021. The increase per Boe for the year ended December 31, 2022 compared with the year ended December 31, 2021 was primarily related to higher expense related to workovers and inflationary pressure on service costs. The increased workover costs were responsible for approximately $0.60/Boe of the increase.

Production Tax Expense. Total production taxes increased to $24.1 million for the year ended December 31, 2022 from $15.0 million for the year ended December 31, 2021. Production taxes are primarily based on oil revenue and gas production, excluding gains and losses associated with hedging activities. Production taxes as a percentage of oil and natural gas sales before hedging adjustments were 8.5% for both years ended December 31, 2022 and 2021.

General and Administrative Expense. General and administrative expense increased to $19.8 million for the year ended December 31, 2022 from $10.7 million for the year ended December 31, 2021. General and administrative expense on a per Boe basis increased to $5.24 for the year ended December 31, 2022 from $2.96 for the year ended December 31, 2021. The increase in general and administrative expense on a per Boe basis was primarily related to costs related to the Spin-Off of $7.9 million. Excluding costs related to the Spin-Off the per BOE rate in calendar 2022 would have been $3.15 per BOE. The slight increase in general and administrative expense per BOE, excluding the Spin-Off costs, was primarily due to legal fees incurred for our litigation against one operator regarding excessive deductions taken against our revenue.

DD&A. DD&A increased to $63.7 million for the year ended December 31, 2022 compared with $60.9 million for the year ended December 31, 2021. The increase of $2.8 million, or 5% was the result of a 4% increase in production and a minimal increase in the DD&A rate for the year ended December 31, 2022 compared with the year ended December 31, 2021. The increase in production accounted for a $2.7 million increase in DD&A expense while the increase in the DD&A rate accounted for a $0.1 million increase in DD&A expense.

Unit-based Compensation. Unit-based compensation expense is recorded for in-substance call options granted to the founding members of management which are classified as liabilities and recorded at estimated fair value at each period end. Unit-based compensation expense is also recognized for management incentive units granted to other employees which are classified as liabilities until the holder has borne the risk of unit ownership. Unit-based compensation expense is recorded as these units vest and expense or contra-expense is recognized as the estimated fair value of the liability changes with market conditions. Unit-based compensation expense was a negative $10.8 million for the year ended December 31, 2022 compared to $4.0 million for the year ended December 31, 2021 primarily due to a reduced value of the options due to a shortened time until exercise and lower volatility as these instruments were settled in conjunction with the Spin-Off.

Interest Expense. Interest expense increased to $4.2 million for the year ended December 31, 2022 from $3.1 million for the year ended December 31, 2021. The increase for the year ended December 31, 2022 was due to a higher SOFR interest rate in the year ended December 31, 2022 despite the balance on our Prior Revolving Credit Facility declining to $48.0 million at December 31, 2022 from $68.0 million at December 31, 2021. The higher interest rate was due to increases to the federal funds rate by the Federal Reserve throughout 2022.

Commodity Derivative Gain (Loss). Commodity derivative loss was $30.8 million for the year ended December 31, 2022 compared with a loss of $39.9 million for the year ended December 31, 2021. Gain (Loss) on Commodity Derivatives is comprised of (1) cash gains and losses we recognize on settled commodity derivative instruments during the period, and (2) unsettled gains and losses we incur on commodity derivative instruments outstanding at period-end.

The mark-to-market fair value of the unsettled commodity derivative instruments will generally be inversely related to the price movement of the underlying commodity. If commodity price trends reverse from period to period, prior unrealized gains may become unrealized losses and vice versa. These unrealized gains and losses will impact our net income in the period reported. The mark-to-market fair value can create non-cash volatility in our reported earnings during periods of commodity price volatility. We have experienced such volatility in the past and are likely to experience it in the future. Gains on our derivatives generally indicate lower oil revenues in the future while losses indicate higher future oil revenues.

The table below summarizes our commodity derivative gains and losses that were recorded in the periods presented.

(in thousands)	YEAR END DECEMBER 31, 2022	2021
Realized gain (loss) on commodity derivatives [(1)]	$ (47,124)	$ (16,914)
Unrealized gain (loss) on commodity derivatives [(1)]	16,294	(22,977)
Total commodity derivative gain (loss)	$ (30,830)	$ (39,891)

(1) Realized and unrealized gains and losses on commodity derivatives are presented herein as separate line items but are combined for a total commodity derivative gain (loss) in the consolidated statements of operations included in this Annual Report on Form 10-K. Management believes the separate presentation of the realized and unrealized commodity derivative gains and losses is useful because the realized cash settlement portion provides a better understanding of our hedge position.

In 2022, approximately 55% of our oil volumes and 6% of our natural gas volumes were covered by financial hedges, which resulted in a realized loss on oil derivatives of $46.5 million and a realized loss on natural gas derivatives of $0.6 million after settlements. In 2021, approximately 47% of our oil volumes and 11% of our natural gas volumes were subject to financial hedges, which resulted in a realized loss on oil derivatives of $16.1 million and a realized loss on natural gas derivatives of $0.8 million after settlements.

Liquidity and Capital Resources

Overview. At December 31, 2023, we had $0.6 million of unrestricted cash on hand and $164.0 million available under our borrowing base. At December 31, 2022, we had $10.0 million of unrestricted cash on hand and $152.0 million available under our borrowing base in our Prior Revolving Credit Facility. We expect that our liquidity going forward will be primarily derived from cash flows from our operations, cash on hand and availability under the Revolving Credit Facility and that these sources of liquidity will be sufficient to provide us the ability to fund our material cash requirements for the next twelve months, as described below, including our planned capital expenditures program, as well as dividends and our share repurchase program. We may need to fund acquisitions or other business opportunities that support our strategy through additional borrowings under our Revolving Credit Facility or the issuance of equity or debt. Our primary uses of capital have been for the acquisition and development of our oil and natural gas properties and dividend payments. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

Working Capital. Our working capital balance fluctuates as a result of changes in commodity pricing and production volumes, the collection of revenue receivables, expenditures related to our acquisition and development, and production operations and the impact of our outstanding commodity derivative instruments. Excess liquidity was retained at December 31, 2022 in anticipation of fees related to the Spin-Off that were paid in early 2023.

At December 31, 2023, we had a working capital deficit of $2.1 million, compared to a surplus of $17.7 million at December 31, 2022. Current assets increased by $4.0 million while current liabilities increased by $23.7 million at December 31, 2023, compared to December 31, 2022. The increase in current assets in 2023 as compared to 2022 was primarily due to an increase of $7.9 million in our commodity derivative instruments due to forward oil price decreases and more advantageous hedge instruments in place at December 31, 2023, and an increase of $3.5 million in revenue receivable primarily due to higher oil and natural gas revenue in the fourth quarter, partially offset by a decreased cash balance of $9.5 million. The change in current liabilities in 2023 as compared to 2022 was primarily due to an increase of $27.1 million in accounts payable and accrued liabilities as a result of increased development activity offset by a decrease of $3.4 million in derivative instrument liabilities as a result of forward oil price decreases and more advantageous hedge instruments in place at December 31, 2023.

Cash Flows. Our cash flows for the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021 are presented below:

(in thousands)	FOR THE YEARS ENDED DECEMBER 31, 2023	2022	FOR THE MONTH ENDED DECEMBER 31, 2021	FOR THE YEAR ENDED NOVEMBER 30, 2021
Cash flows provided by operating activities	$ 141,942	$ 147,041	$ 12,520	$ 86,971
Cash flows used in investing activities	(120,666)	(84,583)	(3,956)	(43,317)
Cash flows used in financing activities	(30,731)	(57,807)	(6,009)	(42,587)
Net (decrease) increase in cash	$ (9,455)	$ 4,651	$ 2,555	$ 1,067

During the year ended December 31, 2023, we generated $141.9 million of cash from operations, a decrease of 3% from the year ended December 31, 2022 despite a 17% decrease in total revenue. During the year ended December 31, 2022, we generated

$147.0 million of cash from operating activities, an increase of $60.1 million from the year ended November 30, 2021. Cash flows from operations are primarily affected by production volumes and commodity prices, net of the effects of settlements of our derivative contracts, and by changes in working capital. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our Revolving Credit Facility. We typically enter into commodity derivative transactions covering a substantial, but varying, portion of our anticipated future oil and gas production for the next 12 to 24 months. A minimum level of derivative coverage is required by certain debt covenants. See Part II. Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

One of the primary sources of variability in our cash provided by operating activities is commodity price volatility, which we partially mitigate through the use of commodity derivative contracts. As of December 31, 2023, we had oil swaps covering 1,374,998 Bbls at a weighted average price of $78.95 per Bbl for calendar 2024 and oil swaps covering the sale of 180,000 Bbls at a weighted average price of $75.30 per Bbl for calendar 2025. As of December 31, 2023, we had no natural gas derivative contracts. For more information on our outstanding derivatives, see Notes to Consolidated Financial Statements—Note 6—Derivative Instruments.

Cash used in investing activities during the years ended December 31, 2023 and 2022 was $120.7 million and $84.6 million, respectively, as compared to $43.3 million during the year ended November 30, 2021 and $4.0 million during the month ended December 31, 2021. Cash used in investing activities primarily relates to capital expenditures for acquisition and development costs. The reduced level of cash used in investing activities in 2021 was primarily attributable to reduced development activity by our operators due to the COVID-19 pandemic, while increased activity during the years ended December 31, 2023 and December 31, 2022 represent a recovery from these same factors. Our cash used in investing activities reflects actual cash spending, which can lag several months from when the related costs were accrued. As a result, our actual cash spending is not always reflective of current levels of development activity. Acquisition and development activities are discretionary. We monitor our capital expenditures on a regular basis, adjusting the amount up or down, and between projects, depending on projected commodity prices, cash flows and financial returns. We supplement development activity on our asset base with opportunistic acquisitions of near-term drilling opportunities when development activity by our operators on our existing properties does not meet our development objectives. Our cash spending for acquisition activities was $35.7 million, $28.5 million and $6.2 million during the fiscal years ended December 31, 2023, December 31, 2022, and November 30, 2021, respectively, and $0.1 million in the month ended December 31, 2021.

Cash used in financing activities was $30.7 million, $57.8 million, and $42.6 million during the fiscal years ended December 31, 2023, December 31, 2022, and November 30, 2021, respectively, and $6.0 million during the month ended December 31, 2021. The cash used in financing activities during the fiscal years ended December 31, 2022 and November 30, 2021 was related to $20.0 million and $30.5 million, respectively, of net repayments under our Prior Revolving Credit Facility as compared to net borrowings of $28.0 million during the fiscal year ended December 31, 2023 under our Revolving Credit Facility. Additionally, we paid distributions to our equity holders of $58.0 million, $36.0 million and $12.0 million during the fiscal years ended December 31, 2023, December 31, 2022, November 30, 2021, respectively, and $6.0 million during the month ended December 31, 2021.

Prior Revolving Credit Facility. See Notes to the Consolidated Financial Statements —Note 5—Credit Facility for further details regarding the Prior Revolving Credit Facility.

Revolving Credit Facility. In connection with the Spin-Off, we entered into the secured Revolving Credit Facility. The Revolving Credit Facility amends and restates the Prior Revolving Credit Facility.

The Predecessor, as predecessor borrower under the Prior Revolving Credit Facility, assigned the liens and its existing rights, liabilities and obligations under the Prior Revolving Credit Facility to Vitesse. Vitesse then entered into the Revolving Credit Facility with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of banks, as lenders. The Revolving Credit Facility will mature on April 29, 2026.

Under the Revolving Credit Facility, we are permitted to make cash distributions without limit to our equity holders if (i) no event of default or borrowing base deficiency (i.e., outstanding debt (including loans and letters of credit) exceeds the borrowing base) then exists or would result from such distribution and (ii) after giving effect to such distribution, (a) our total outstanding credit usage does not exceed 80% of the least of (the following collectively referred to as “Commitments”): (1) $500 million, (2) our then-effective borrowing base, and (3) the then-effective aggregate amount of the aggregate elected commitments and (b) as of the date of such distribution, the EBITDAX Ratio does not exceed 1.50 to 1.00. If our EBITDAX Ratio does not exceed 2.25 to 1.00, and if our total outstanding credit usage does not exceed 80% of the Commitments, we may also make distributions if our free cash flow (as defined under the Revolving Credit Facility) is greater than $0 and we have delivered a certificate to our lenders attesting to the foregoing.

As of December 31, 2023, the Company’s borrowing base was $245.0 million with an aggregate elected commitment of $180.0 million of which $81.0 million was outstanding. On January 17, 2024, the Company increased the elected commitments to

$210 million and added a fifth lender to the syndicate of banks. See Notes to Consolidated Financial Statements—Note 5—Credit Facility for further details regarding the Revolving Credit Facility.

Material Cash Requirements. Our material short-term cash requirements include payments under our short-term lease agreements, recurring payroll and benefits obligations for our employees, capital and operating expenditures and other working capital needs. As commodity prices improve, our working capital requirements may increase as we spend additional capital, increase production and pay larger settlements on our outstanding commodity derivative contracts.

Our long-term material cash requirements from currently known obligations include settlements on our outstanding commodity derivative contracts, future obligations to plug, abandon and remediate our oil and gas properties at the end of their productive lives, and operating lease obligations. We cannot provide specific timing for repayments of outstanding borrowings on our Revolving Credit Facility, or the associated interest payments, as the timing and amount of borrowings and repayments cannot be forecasted with certainty and are based on working capital requirements, commodity prices and acquisition and divestiture activity, among other factors. We cannot provide specific timing for other current and long-term liability obligations where we cannot forecast with certainty the amount and timing of such payments, including asset retirement obligations, as the plugging and abandonment of wells is at the discretion of the operators and any amounts we may be obligated to pay under our derivative contracts, as such payments are dependent on commodity prices in effect at the time of settlement. See Notes to Consolidated Financial Statements—Note 4— Fair Value Measurements for further information on these contracts and their fair values as of December 31, 2023, which fair values represent the estimated cash settlement amount required to terminate such instruments based on forward price curves for commodities as of that date.

*Dividends. W*e paid cash dividends to our equity holders of $58.0 million during the year ended December 31, 2023. While we believe that our future cash flows from operations will be able to sustain the current level of dividends, future dividends may change based on a variety of factors, including contractual restrictions, legal limitations (the most common of which are limitations set forth in a company’s organizational documents and insolvency), business developments and the judgment of our Board. Future cash dividends to equity holders are subject to the terms of the Revolving Credit Facility, as previously described. There can be no guarantee that we will be able to pay dividends at current levels or at all or otherwise return capital to our investors in the future.

Capital Expenditures. For the year ended December 31, 2023 total capital expenditures was $120.5 million, including development expenditures and our acquisition activity. We expect to fund future capital expenditures with cash generated from operations and, if required, borrowings under our Revolving Credit Facility. The foregoing excludes larger acquisitions, which are typically not included in our annual capital expenditures budget. With our cash on hand, cash flow from operations, and borrowing capacity under our Revolving Credit Facility, we believe that we will have sufficient cash flow and liquidity to fund our budgeted capital expenditures and operating expenses for at least the next twelve months. However, we may seek additional access to capital and liquidity including issuing equity or debt securities and extending maturities. We cannot assure you, however, that any additional capital will be available to us on favorable terms or at all. Our capital expenditures could be curtailed if our cash flows decline or we are otherwise unable to access capital or liquidity. Reductions of capital expenditures used to drill and complete new oil and natural gas wells would likely result in lower levels of oil and natural gas production in the future. Our future success in growing proved reserves and production may be dependent on our ability to access outside sources of capital.

The amount, timing and allocation of capital expenditures are largely discretionary and subject to change based on a variety of factors. If oil and natural gas prices decline below our acceptable levels, or costs increase, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected financial returns and potential to generate near-term cash flow. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We will carefully monitor and may adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing and joint venture opportunities, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, change in service costs, contractual obligations, internally generated cash flow and other factors both within and outside our control. For additional information on the impact of changing prices and market conditions on our financial position, see Part II. Item 7A Quantitative and Qualitative Disclosures About Market Risk.

Effects of Inflation and Pricing. The oil and natural gas industry is cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put pressure on the economic stability and pricing structure within the industry. Higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel, which we have seen in 2023 and 2022 compared to 2021. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Such changes can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. Despite these effects of inflation and pricing, we expect to continue generating significant amounts of free cash flow at current commodity price levels.

Non-GAAP Financial Information

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure for proved reserves. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at ten percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. PV-10 and the Standardized Measure do not purport to represent the fair value of our oil and natural gas reserves.

The table below reconciles the pre-tax PV-10 value of our proved reserves at SEC prices as of December 31, 2023 to the Standardized Measure.

(in thousands)	FOR THE YEAR ENDED DECEMBER 31, 2023
Pre-Tax Present Value of Estimated Future Net Revenues (Pre-Tax PV10%)	$ 682,070
Future Income Taxes, Discounted at 10%	$ (106,379)
Standardized Measure of Discounted Future Net Cash Flows	$ 575,691

Uncertainties are inherent in estimating quantities of proved reserves, including many risk factors beyond our control. Reserve engineering is a subjective process of estimating subsurface accumulations of oil and natural gas that cannot be measured in an exact manner. As a result, estimates of proved reserves may vary depending upon the engineer estimating the reserves. Further, our actual realized price for our oil and natural gas is not likely to equal the pricing parameters used to calculate our proved reserves. As such, the oil and natural gas quantities and the value of those commodities ultimately recovered from our properties will vary from reserve estimates.

Additional discussion of our proved reserves is set forth under Notes to Consolidated Financial Statements—Supplemental Oil and Gas Information (Unaudited).

Critical Accounting Policies and Estimates

We prepare our financial statements and the accompanying notes in conformity with accounting principles generally accepted in the United States, which require management to make estimates and assumptions about future events that affect the reported amounts in the financial statements and the accompanying notes. We identify certain accounting policies and estimates as critical based on, among other things, their impact on our financial condition, results of operations, and the degree of difficulty, subjectivity and complexity in their application. Critical accounting policies and estimates cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Management routinely discusses the development, selection and disclosure of each of the critical accounting policies and estimates. The following is a discussion of our most critical accounting policies and estimates.

Proved Oil and Natural Gas Reserves

The determination of depreciation, depletion and amortization expense as well as impairments that may be recognized on our oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. Approximately 30% of our proved oil and gas reserve volumes are categorized as proved undeveloped reserves. Any significant variance in these assumptions could materially affect the estimated quantity and value of our reserves, future cash flows from our reserves, and future development of our proved undeveloped reserves. Our proved oil and gas reserve information was computed by applying the average first-day-of-the- month oil and gas price during the 12-month period ended on the balance sheet date.

External petroleum engineers independently estimated all of the proved reserve quantities included in our financial statements for the year ended December 31, 2023, which were prepared in accordance with the rules promulgated by the SEC. In connection with our external petroleum engineers performing their independent reserve estimations, we furnish them with the following information: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for oil and gas activities. Under this method of accounting, costs associated with the acquisition, drilling, and equipping of successful exploratory wells and costs of successful and unsuccessful development wells are capitalized and depleted, net of estimated salvage values, using the units-of-production method on the basis of a reasonable aggregation of properties within a common geological structural feature or stratigraphic condition, such as a reservoir or field.

We review our oil and natural gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. If we determined an evaluation for impairment is required, we estimate the expected future cash flows of our oil and natural gas properties and compare such cash flows to the carrying amount of the proved oil and natural gas properties to determine if the amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying value of proved oil and natural gas properties to estimated fair value. The factors used to estimate fair value include estimates of reserves, future commodity prices adjusted for basis differentials, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the projected cash flows. The discount rate is a rate that management believes is representative of current market conditions and includes estimates for a risk premium and other operational risks.

For the years ended December 31, 2023, December 31, 2022, and November 30, 2021 and the month ended December 31, 2021 we did not record any impairment expense.

Equity-Based Compensation

The Company recognizes equity-based compensation expense associated with its long-term incentive plan (“LTIP”) awards using the straight-line method over the requisite service period, which is generally the vesting period of the award except when provisions are present that accelerate vesting, based on their grant date fair values. The Company has elected to account for forfeitures of equity awards as they occur.

Previous grants of 180,875 RSUs were forfeited during the year ended December 31, 2023. In January 2024, 792,000 restricted stock units vested with the Company retaining 332,840 of the vested shares to fund employee tax withholding of $6.9 million with the retained shares subsequently retired by the Company.

Predecessor Equity-Based Compensation

In 2020, the Predecessor amended the Predecessor Company Agreement which modified certain terms and conditions related to management incentive units (“MIUs”) and common units held by the founding members of management. The Predecessor accounted for MIUs granted to employees (which excludes the founding members of management) as liability awards under accounting guidance related to share-based compensation, whereby vested awards are recognized as liabilities, with changes in the estimated value of the awards recorded in earnings, until the holders have borne the risk of unit ownership, at which point the liability associated with the employee MIUs is reclassified to temporary equity, and changes in the estimated value of the MIUs are recorded as an adjustment to members’ equity.

Equity-based compensation was also recognized for in-substance call options granted to the founding members of management which were classified as liabilities, recorded at estimated fair market value at each period end. Changes in the estimated fair value were recorded in earnings. As the Predecessor was a private entity whose units were not traded, we considered the average volatility of comparable entities to develop an estimate of expected volatility which resulted in a reasonable estimate of fair value.

Recently Issued or Adopted Accounting Pronouncements

For discussion of recently issued or adopted accounting pronouncements, see Notes to the Consolidated Financial Statements—Note 2—Significant Accounting Policies.”

Off Balance Sheet Arrangements

We currently do not have any off-balance sheet arrangements that have or are reasonably likely to have a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Item 7A. Quantitative and Qualitative Disclosure about Market Risk

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities, and, as a result, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand and other factors. Historically, the markets for oil and natural gas have been volatile, and we believe these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenue generally would have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil that also increase and decrease along with oil prices.

We enter into derivative contracts to achieve a more predictable cash flow by reducing our exposure to commodity price volatility. All derivative positions are carried at their fair value on the balance sheet and are marked-to-market at the end of each period. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to gain (loss) on derivative instruments, net on the statements of operations rather than as a component of other comprehensive income or other income (expense).

We generally use derivatives to economically hedge a significant, but varying portion of our anticipated future production. Any payments due to counterparties under our derivative contracts are funded by proceeds received from the sale of our production. Production receipts, however, lag payments to the counterparties. Any interim cash needs are funded by cash from operations or borrowings under our Revolving Credit Facility.

The following table summarizes our open crude oil swap contracts as of December 31, 2023, by fiscal quarter.

SETTLEMENT PERIOD	OIL (barrels)	WEIGHTED AVERAGE PRICE $
Swaps-Crude Oil		
2024:		
Q1	402,498	$ 79.03
Q2	382,500	$ 79.13
Q3	327,500	$ 78.50
Q4	262,500	$ 78.53
2025:		
Q1	90,000	$ 75.30
Q2	90,000	$ 75.30

See Notes to the Consolidated Financial Statements—Note 4—Fair Value Measurements and —Note 6—Derivative Instruments for further details regarding our commodity derivatives.

Based upon our open commodity derivative positions at December 31, 2023, a hypothetical $1 increase or decrease in the NYMEX WTI strip price would increase or decrease our net commodity derivative position by approximately $1.5 million. The hypothetical change in fair value could be a gain or a loss depending on whether commodity prices decrease or increase.

Interest Rate Risk

Our long-term debt is composed of borrowings that contain floating interest rates. Our Revolving Credit Facility interest rate is a floating rate option that is designated by us within the parameters established by the underlying agreement. At our option, borrowings under the Revolving Credit Facility bear interest at either an adjusted forward-looking term rate based on SOFR (“Term SOFR”) or an adjusted base rate (“Base Rate”) (the highest of the administrative agent’s prime rate, the Federal Funds Rate plus 0.50% or the 30-day Term SOFR rate plus 1.0%), plus a spread ranging from 1.75% to 2.75% with respect to Base Rate borrowings and 2.75% to 3.75% with respect to Term SOFR borrowings, in each case based on the borrowing base utilization percentage. All outstanding principal is due and payable upon termination of the Revolving Credit Facility. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the average interest rate would be an approximate $0.5 million increase or decrease in interest expense for the year ended December 31, 2023.

Item 8. Financial Statements and Supplementary Data

The information required by this Item is included in this Annual Report as set forth in the "Index to Financial Statements" on page F-1 of this report and is incorporated herein by reference.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosures

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15(b) of the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2023. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2023 at the reasonable assurance level. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objective and management necessarily applies its judgment in evaluating the cost-benefit relationship of all possible controls and procedures.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the fourth quarter of 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

This annual report does not include a report on management's assessment regarding internal control over financial reporting due to a transition period established by the rules of the SEC for newly public companies.

Attestation Report of the Registered Public Accounting Firm

This annual report does not include an attestation report regarding the effectiveness of our internal controls over financial reporting of our independent registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies. Further, our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal controls over financial reporting for as long as we are an "emerging growth company" pursuant to the provisions of the JOBS Act.

Item 9B. Other Information

During the fiscal quarter ended December 31, 2023, none of our officers or directors, as defined in Rule 16a-1(f), informed us of the adoption, modification or termination of any "Rule 10b5-1 trading arrangement" or a "non-Rule 10b5-1 trading arrangement," as those terms are defined in Item 408 of Regulation S-K.

Item 9C. Disclosure Regarding Foreign Jurisdiction that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following table presents information, as of February 26, 2024, regarding the individuals who are serving as executive officers and directors of Vitesse:

NAME	AGE	POSITION
Robert W. Gerrity	72	Chairman, Chief Executive Officer
Brian J. Cree	60	President
James P. Henderson	58	Chief Financial Officer
Linda Adamany	71	Director
Brian P. Friedman	68	Director
Daniel O’Leary	68	Lead Independent Director
Cathleen M. Osborn	71	Director
Randy Stein	70	Director
Joseph S. Steinberg	80	Director

Information regarding our Code of Conduct and Business Ethics, Code of Ethics For Senior Financial Officers and Corporate Governance Guidelines for our principal executive officer and principal financial officer are available on the Company’s website under the heading “Investor Relations”, the subheading “Governance,” and the subheading “Governance Documents.” References to the Company's website in this Annual Report on Form 10-K are provided as a convenience and do not constitute, and should not be deemed, an incorporation by reference of the information contained on, or available through, the website, and such information should not be considered part of this Annual Report on Form 10-K.

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 10 the information not otherwise disclosed in this Item 10 and to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

Item 11. Executive Compensation

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 11 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 12 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

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

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 13 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

Item 14. Principal Accounting Fees and Services

Pursuant to paragraph 3 of General Instruction G to Form 10-K, we incorporate by reference into this Item 14 the information to be disclosed in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

PART IV

Item 15. Exhibits, Financial Statement Schedules

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

The consolidated financial statements are listed on the Index to Financial Statements to this report beginning on page F-1.

(a)(3) Exhibits.

Exhibit No.	Description	Reference
2.1*	Separation and Distribution Agreement, dated as of January 13, 2023, by and among Jefferies Financial Group Inc., Vitesse Energy Finance LLC, Vitesse Energy, Inc., and the other signatories listed therein	Incorporated by reference to Exhibit 2.1 to Form 8-K filed January 17, 2023, File No. 001-41546
3.1	Amended and Restated Certificate of Incorporation of Vitesse Energy, Inc.	Incorporated by reference to Exhibit 3.1 to Form 8-K filed January 17, 2023, File No. 001-41546
3.2	Amended and Restated Bylaws of Vitesse Energy, Inc.	Incorporated by reference to Exhibit 3.2 to Form 8-K filed January 17, 2023, File No. 001-41546
4.1	Description of Vitesse Energy, Inc.'s Common Stock	Filed herewith.
10.1	Tax Matters Agreement, dated as of January 13, 2023, between Jefferies Financial Group Inc. and Vitesse Energy, Inc.	Incorporated by reference to Exhibit 10.1 to Form 8-K filed January 17, 2023, File No. 001-41546
10.2*	Second Amended and Restated Credit Agreement, dated as of January 13, 2023, among Vitesse Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto	Incorporated by reference to Exhibit 10.2 to Form 8-K filed January 17, 2023, File No. 001-41546
10.3	First Amendment to Second Amended and Restated Credit Agreement dated as of May 2, 2023, among Vitesse Energy, Inc., as borrower, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto	Incorporated by reference to Exhibit 10.3 to Form 10-Q filed May 8, 2023, File No. 001-41546
10.4†	Vitesse Energy, Inc. Long-Term Incentive Plan	Incorporated by reference to Exhibit 10.3 to Form 8-K filed January 17, 2023, File No. 001-41546
10.5†*	Vitesse Energy, Inc. Transitional Equity Award Adjustment Plan*	Incorporated by reference to Exhibit 10.4 to Form 8-K filed January 17, 2023, File No. 001-41546
10.6†*	Letter Agreement, dated as of January 13, 2023, by and among Vitesse Management Company LLC, Vitesse Energy, LLC, Vitesse Oil, LLC, Vitesse Energy, Inc. and Bob Gerrity	Incorporated by reference to Exhibit 10.5 to Form 8-K filed January 17, 2023, File No. 001-41546
10.7†*	Letter Agreement, dated as of January 13, 2023, by and among Vitesse Management Company LLC, Vitesse Energy, LLC, Vitesse Oil, LLC, Vitesse Energy, Inc. and Brian Cree	Incorporated by reference to Exhibit 10.6 to Form 8-K filed January 17, 2023, File No. 001-41546
10.8†	Form of RSU Award Agreement (Executive – Retirement)	Incorporated by reference to Exhibit 10.9 to the Registration Statement on Form 10, declared effective January 6, 2023, File No. 001-41546
10.9†	Form of RSU Agreement (Executive – Three Year Vesting)	Incorporated by reference to Exhibit 10.10 to the Registration Statement on Form 10, declared effective January 6, 2023, File No. 001-41546
10.10†	Form of RSU Agreement (Employee – Four Year Vesting)	Incorporated by reference to Exhibit 10.11 to the Registration Statement on Form 10, declared effective January 6, 2023, File No. 001-41546
10.11†	Form of RSU Agreement (Director)	Incorporated by reference to Exhibit 10.10 to Form 10-K filed February 16, 2023, File No. 001-41546
10.12†	Letter Agreement, dated September 11, 2023, by and between Vitesse Energy, Inc. and David R. Macosko	Incorporated by reference to Exhibit 10.1 to Form 10-Q filed November 1, 2023, File No. 0001-41456

10.13†	Form of Performance Stock Unit Grant Notice	Filed herewith.
21.1	List of Subsidiaries	Filed herewith.
23.1	Vitesse Energy, Inc. Consent of Deloitte & Touche LLP	Filed herewith.
23.2	Consent of Cawley, Gillespie & Associates	Filed herewith.
31.1	Certification of the Chief Executive Officer required by Rule 13a, 14(a) or Rule 15d-14(a)	Filed herewith.
31.2	Certification of the Chief Financial Officer required by Rule 13a, 14(a) or Rule 15d-14(a)	Filed herewith.
32.1	Certification of the Chief Executive Officer and Chief Financial Officer required by Rule 13a, 14(a) or Rule 15d-14(a)	Filed herewith.
97.1	Vitesse Energy, Inc. Incentive-Based Compensation Recoupment Policy, adopted as of October 31, 2023.	Filed herewith.
99.1	Report of Cawley, Gillespie & Associates as of December 31, 2023	Filed herewith.

† Compensatory plan or arrangement.

* Certain schedules and similar attachments have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The registrant undertakes to furnish supplemental copies of any of the omitted schedules upon request by the Securities and Exchange Commission.

Item 16. Form 10-K Summary

None.

SIGNATURES

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

Vitesse Energy, Inc.

Date: February 26, 2024 By: /s/ Robert W. Gerrity

Name: Robert W. Gerrity

Title: Chairman, Chief Executive Officer

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

Signature	Title	Date
/s/ Robert W. Gerrity Robert W. Gerrity	Chairman, Chief Executive Officer (Principal Executive Officer)	February 26, 2024
/s/ James P. Henderson James P. Henderson	Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2024
/s/ Linda Adamany Linda Adamany	Director	February 26, 2024
/s/ Brian P. Friedman Brian P. Friedman	Director	February 26, 2024
/s/ Daniel O'Leary Daniel O'Leary	Director	February 26, 2024
/s/ Cathleen M. Osborn Cathleen M. Osborn	Director	February 26, 2024
/s/ Randy Stein Randy Stein	Director	February 26, 2024
/s/ Joseph S. Steinberg Joseph S. Steinberg	Director	February 26, 2024

VITESSE ENERGY, INC.
INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of Vitesse Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vitesse Energy, Inc. and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, equity, and cash flows for the years ended December 31, 2023 and 2022, the one-month period ended December 31, 2021, and for the year ended November 30, 2021, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for the years ended December 31, 2023 and 2022, the one-month period ended December 31, 2021, and year ended November 30, 2021, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

/s/ Deloitte & Touche LLP

Denver, Colorado
February 26, 2024

We have served as the Company’s auditor since 2021.

VITESSE ENERGY, INC.
Consolidated Balance Sheets

(in thousands except units)	DECEMBER 31, 2023	DECEMBER 31, 2022
Assets		
Current Assets		
Cash	$ 552	$ 10,007
Revenue receivable	44,915	41,393
Commodity derivatives (Note 6)	10,038	2,112
Prepaid expenses and other current assets	2,841	841
Total current assets	58,346	54,353
Oil and Gas Properties-Using the successful efforts method of accounting (Note 2)		
Proved oil and gas properties	1,168,378	985,751
Less accumulated DD&A and impairment	(464,036)	(382,974)
Total oil and gas properties	704,342	602,777
Other Property and Equipment—Net	189	114
Other Assets		
Commodity derivatives (Note 6)	1,109	1,155
Other noncurrent assets	1,984	2,085
Total other assets	3,093	3,240
Total assets	$ 765,970	$ 660,484
Liabilities, Redeemable Units and Equity		
Current Liabilities		
Accounts payable	$ 27,692	$ 7,207
Accrued liabilities (Note 7)	32,507	25,849
Commodity derivatives (Note 6)	—	3,439
Other current liabilities	204	184
Total current liabilities	60,403	36,679
Long-term Liabilities		
Revolving credit facility (Note 5)	81,000	48,000
Deferred tax liability (Note 13)	64,329	—
Asset retirement obligations (Note 8)	8,353	6,823
Other noncurrent liabilities	5,479	—
Total liabilities	219,564	91,502
Commitments and contingencies (Note 11)		
Redeemable Management Incentive Units (Note 12)	—	4,559
Equity (Note 12)		
Preferred stock, $0.01 par value, 5,000,000 shares authorized; 0 shares issued at December 31, 2023	—	—
Common stock, $0.01 par value, 95,000,000 shares authorized; 32,812,007 shares issued at December 31, 2023	328	—
Additional paid-in capital	567,654	—
Accumulated deficit	(21,576)	—
Predecessor members' equity-common units-450,000,000 units outstanding (Note 12)	—	564,423
Total liabilities, redeemable units, and equity	$ 765,970	$ 660,484

See notes to consolidated financial statements

VITESSE ENERGY, INC.
Consolidated Statements of Operations

(in thousands, except per share data)	FOR THE YEARS ENDED DECEMBER 31, 2023	FOR THE YEARS ENDED DECEMBER 31, 2022	FOR THE MONTH ENDED DECEMBER 31, 2021	FOR THE YEAR ENDED NOVEMBER 30, 2021
Revenue				
Oil	$ 218,396	$ 233,622	$ 14,797	$ 144,818
Natural gas	15,509	48,268	1,669	23,017
Total revenue	233,905	281,890	16,466	167,835
Operating Expenses				
Lease operating expense	39,514	31,133	2,272	26,567
Production taxes	21,625	24,092	1,340	14,535
General and administrative	23,934	19,833	950	10,581
Depletion, depreciation, amortization, and accretion	81,745	63,732	5,417	60,846
Equity-based compensation (Note 12)	32,233	(10,766)	2,628	1,409
Total operating expenses	199,051	128,024	12,607	113,938
Operating Income	34,854	153,866	3,859	53,897
Other Income (Expense)				
Commodity derivative gain (loss), net	12,484	(30,830)	(10,982)	(32,590)
Interest expense	(5,276)	(4,153)	(237)	(3,207)
Other income	140	20	1	14
Total other income (expense)	7,348	(34,963)	(11,218)	(35,783)
Income (Loss) Before Income Taxes	$ 42,202	$ 118,903	$ (7,359)	$ 18,114
(Provision for) Benefit from Income Taxes	(61,946)	—	—	—
Net (Loss) Income	$ (19,744)	$ 118,903	$ (7,359)	$ 18,114
Net income (loss) attributable to Predecessor common unit holders	1,832	118,903	(7,359)	18,114
Net Loss Attributable to Vitesse Energy, Inc.	$ (21,576)	$ —	$ —	$ —
Weighted average common shares / Predecessor common unit outstanding – basic	29,556,967	438,625,000	438,625,000	438,625,000
Weighted average common shares / Predecessor common unit outstanding – diluted	29,556,967	438,625,000	438,625,000	438,625,000
Net (loss) income per common share / Predecessor common unit – basic	$ (0.73)	$ 0.26	$ (0.02)	$ 0.04
Net (loss) income per common share / Predecessor common unit – diluted	$ (0.73)	$ 0.26	$ (0.02)	$ 0.04
Net loss per Predecessor non-founder MIUs classified as temporary equity–basic and diluted		$ —	$ —	$ —

See notes to consolidated financial statements

VITESSE ENERGY, INC.
Consolidated Statements of Equity

	Common Stock		Preferred Stock					
(in thousands, except share data)	Shares	Amount	Shares	Amount	Additional Paid-In Capital	Predecessor Members' Equity	Accumulated Deficit	Total Equity
Balance—December 1, 2020	—	$ —	—	$ —	$ —	$ 489,808	$ —	$ 489,808
Net income	—	—	—	—	—	18,114	—	18,114
Distribution to common unit holders	—	—	—	—	—	(12,000)	—	(12,000)
Fair market value MIU adjustment	—	—	—	—	—	(1,530)	—	(1,530)
Balance—November 30, 2021	—	$ —	—	$ —	$ —	$ 494,392	$ —	$ 494,392
Net loss	—	—	—	—	—	(7,359)	—	(7,359)
Distribution to common unit holders	—	—	—	—	—	(6,000)	—	(6,000)
Fair market value MIU adjustment	—	—	—	—	—	(959)	—	(959)
Balance—December 31, 2021	—	$ —	—	$ —	$ —	$ 480,074	$ —	$ 480,074
Net income	—	—	—	—	—	118,903	—	118,903
Distribution to common unit holders	—	—	—	—	—	(36,000)	—	(36,000)
Fair market value MIU adjustment	—	—	—	—	—	1,446	—	1,446
Balance—December 31, 2022	—	$ —	—	$ —	$ —	$ 564,423	$ —	$ 564,423
Net income (loss)	—	—	—	—	—	1,832	(21,576)	(19,744)
Issuance of common stock in exchange for Vitesse Energy, LLC	25,914,891	259	—	—	565,996	(566,255)	—	—
Issuance of common stock in exchange for Non-Founder MIU's	163,544	2	—	—	4,557	—	—	4,559
Acquisition of Vitesse Oil, LLC	2,120,312	21	—	—	30,607	—	—	30,628
Issuance of restricted stock units, net of forfeitures	3,152,247	32	—	—	(152)	—	—	(121)
Issuance of Transitional Plan awards	1,475,613	15	—	—	(15)	—	—	—
Equity-based compensation	—	—	—	—	32,535	—	—	32,535
Common stock dividends declared	—	—	—	—	(65,626)	—	—	(65,626)
Repurchase of common stock	(14,600)	—	—	—	(248)	—	—	(248)
Balance—December 31, 2023	32,812,007	$ 328	—	$ —	$ 567,654	$ —	$ (21,576)	$ 546,406

See notes to consolidated financial statements

VITESSE ENERGY, INC.
Consolidated Statements of Cash Flows

(in thousands)	FOR THE YEARS ENDED DECEMBER 31, 2023	FOR THE YEARS ENDED DECEMBER 31, 2022	FOR THE MONTH ENDED DECEMBER 31, 2021	FOR THE YEAR ENDED NOVEMBER 30, 2021
Cash Flows from Operating Activities				
Net (loss) income	$ (19,744)	$ 118,903	$ (7,359)	$ 18,114
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depletion, depreciation, amortization, and accretion	81,745	63,732	5,417	60,846
Unrealized (gain) loss on derivative instruments	(11,318)	(16,294)	9,307	18,687
Equity-based compensation	32,233	(10,766)	2,628	1,409
Deferred income taxes	61,946	—	—	—
Amortization of debt issuance costs	655	472	27	276
Changes in operating assets and liabilities that provided (used) cash:				
Revenue receivable	(810)	(10,764)	1,330	(15,959)
Prepaid expenses and other current assets	(1,860)	(842)	11	1,921
Accounts payable	2,407	(147)	669	(997)
Accrued liabilities	(3,308)	2,739	493	2,700
Other	(4)	8	(3)	(26)
Net cash provided by Operating Activities	141,942	147,041	12,520	86,971
Cash Flows from Investing Activities				
Acquisition of oil and gas properties	(35,654)	(28,547)	(117)	(6,210)
Development of oil and gas properties	(84,832)	(56,024)	(3,837)	(36,986)
Purchase of property and equipment	(180)	(12)	(2)	(121)
Net cash used in Investing Activities	(120,666)	(84,583)	(3,956)	(43,317)
Cash Flows from Financing Activities				
Proceeds from revolving credit facility	59,000	16,000	—	1,000
Repayments of revolving credit facility	(26,000)	(36,000)	—	(31,500)
Repayments of Vitesse Oil revolving credit facility	(5,000)	—	—	—
Dividends/distributions paid	(57,999)	(36,000)	(6,000)	(12,000)
Repurchases of common stock	(248)	—	—	—
Debt issuance costs	(484)	(1,807)	(9)	(87)
Net cash used in Financing Activities	(30,731)	(57,807)	(6,009)	(42,587)
Net (Decrease) Increase in Cash	(9,455)	4,651	2,555	1,067
Cash—Beginning of year	10,007	5,356	2,801	1,734
Cash—End of year	552	$ 10,007	$ 5,356	$ 2,801
Supplemental Disclosure of Cash Flow Information				
Cash paid for interest	$ 4,734	$ 3,595	$ 182	$ 2,896
Cash paid for income taxes	1,292	—	—	—
Supplemental Disclosure of Noncash Activity				
Oil and gas properties included in accounts payable and accrued liabilities	$ 46,338	$ 21,266	$ 14,352	$ 15,174
Asset retirement obligations capitalized to oil and gas properties	951	347	—	192
Issuance of common stock to acquire Vitesse Oil	30,628	—	—	—
Unit-based compensation liability transferred to redeemable management incentive units	—	481	—	636

See notes to consolidated financial statements

VITESSE ENERGY, INC.
Notes to the Consolidated Financial Statements

Note 1—Nature of Business

Vitesse Energy, Inc. (“Vitesse” or the “Company”) was incorporated under the General Corporation Law of the State of Delaware on August 5, 2022 as a wholly owned subsidiary of an affiliate of Jefferies Financial Group Inc. (“JFG”) for the purpose of effecting the Spin-Off of Vitesse Energy, LLC (the “Predecessor”) by JFG. On January 13, 2023, JFG completed the legal and structural separation of the Predecessor from JFG. To effect the separation, first, JFG and Jefferies Capital Partners (“JCP”), among others, undertook certain pre-Spin-Off Transactions described below:

* Certain members of management of the Predecessor transferred all of their equity interest in the Predecessor to JFG as repayment for loans from affiliates of JFG;
* JFG and other holders of the Predecessor’s equity interests transferred all of their interest in the Predecessor to Vitesse in exchange for newly issued shares of common stock, par value $0.01 per share (“common stock”), of Vitesse;
* Vitesse Oil, LLC ("Vitesse Oil") equity holders transferred their interests in Vitesse Oil to Vitesse in exchange for newly issued shares of Vitesse common stock (the “Vitesse Oil Transaction”);
* Compensation agreements and compensation plans of the Predecessor were eliminated and replaced with new compensation plans of Vitesse, including a long-term incentive plan;
* Vitesse entered into a Revolving Credit Facility, which amended and restated the Predecessor’s credit facility, and used the proceeds to repay in full and terminate the Vitesse Oil Revolving Credit Facility and repay the Predecessor’s credit facility.
* The Predecessor entered into a Separation and Distribution Agreement and Tax Matters Agreement with JFG related to the Spin-Off.

JFG and JCP then distributed the Vitesse outstanding common stock held by each to their respective shareholders, and Vitesse became an independent, publicly traded company. The Company’s common stock began trading on the New York Stock Exchange on January 17, 2023 under the symbol “VTS.”

The issued and outstanding member interests of the Predecessor and Vitesse Oil together represented substantially all of those businesses or investments of JFG and JCP that acquire, develop, manage and monetize non-operated oil and natural gas working, royalty and mineral interests in the United States.

Immediately prior to the completion of the Spin-Off, the Company succeeded to the operations of the Predecessor. As the Predecessor and the Company were under common control, and because the Company was not a substantive entity prior to the Spin-Off, for accounting purposes the Company has succeeded to the operations of the Predecessor. The Vitesse Oil Transaction is accounted for as an asset acquisition by the Company as Vitesse Oil and the Company were not under common control.

The Predecessor is a Delaware limited liability company formed on April 29, 2014. Prior to the Spin-Off, the membership interests in the Predecessor were held approximately 97.5% by affiliates of JFG and approximately 2.5% by 3B Energy, LLC (“3B”), an entity whose members are comprised of certain executives of the Company. Financial information presented for periods ended prior to January 13, 2023 is that of the Predecessor, which was organized as a tax partnership. Therefore, for periods prior to January 13, 2023 the financial statements of the Company do not reflect the impact of income taxes. As noted above, as a result of the Spin-Off, the Predecessor became a wholly owned subsidiary of Vitesse, which is organized as a taxable corporation. Therefore, the financial statements of the Company reflect the impact of income taxes applied to the consolidated results of operations of the Company, including the initial basis differences between tax and financial accounting for our assets and liabilities at the Spin-Off resulting in a one-time charge of $44.1 million to income tax expense. Financial information presented for periods ended on and after January 13, 2023 is that of the Company, which reflects the combined results of the Predecessor and Vitesse Oil.

The business purpose of the Company is to acquire, own, explore, develop, manage, produce, exploit, and dispose of oil and gas properties. The Company is focused on returning capital to stockholders through owning and acquiring non-operated working interest and royalty interest ownership primarily in the core of the Bakken and Three Forks formations in the Williston Basin of North Dakota and Montana. The Company also owns non-operated interests in oil and gas properties in the Central Rockies, including the Denver-Julesburg Basin and the Powder River Basin.

Note 2—Significant Accounting Policies

Change in Estimate that is Inseparable from a Change in Accounting Principle

Effective January 1, 2023, the Company changed its method of recording gathering and transportation (“GT”) costs. Under the current method, GT costs are presented as a deduction to oil and gas revenue, following how these items are reported to us by operators of our oil and gas properties. Prior to January 1, 2023, under our previous method, we determined the GT costs that were reported within production expense versus revenue deductions based on our best estimates using information from all our operators in aggregate. Both methods of determining classification of GT costs are acceptable given that we do not operate any of our oil and gas properties and do not have access to such GT contracts with the customer.

The change represents a change in estimate effected by a change in accounting principle. Although the change does not have a material impact to the financial statements the change in methodology has been applied on a retrospective basis to the prior periods presented in order to conform to the current period presentation. This change results in a reclassification within the statements of operations and has no balance sheet impact, nor does it impact net income, operating income, the gross margin we generate from our interests in oil and gas properties, or cash flows for any period.

Principles of Consolidation

The accompanying consolidated financial statements (the “financial statements”) include the accounts of the Company and its subsidiaries, including the Predecessor, Vitesse Oil, Vitesse Management Company LLC (“Vitesse Management”) and Vitesse Oil, Inc. Intercompany balances and transactions have been eliminated in consolidation.

Segment and Geographic Information

The Company operates in a single reportable segment. The Company’s chief operating decision maker is the Chief Executive Officer. All of the Company’s operations are conducted in the continental United States.

Use of Estimates

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States (“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 financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

Depletion, depreciation, and amortization (“DD&A”) and the evaluation of proved oil and gas properties for impairment are determined using estimates of oil and gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures, which includes lack of control over future development plans as a non-operator. Oil and gas reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. In addition, significant estimates include, but are not limited to, estimates relating to certain crude oil and natural gas revenues and expenses, fair value of assets acquired and liabilities assumed in business combinations, valuation of unit-based compensation, and valuation of commodity derivative instruments. Further, these estimates and other factors, including those outside of the Company’s control, such as the impact of lower commodity prices, may have a significant adverse impact to the Company’s business, financial condition, results of operations and cash flows.

Change in Fiscal Year End

On November 30, 2022, the board of managers of the Predecessor approved a change in the Company's fiscal year end from November 30 to December 31. The Company's 2022 fiscal year began on January 1, 2022 and ended on December 31, 2022. As a result of this change, the Company has also presented financial statements for the month ended December 31, 2021.

Cash and Cash Equivalents

The Company considers all investments with an original maturity of three months or less when purchased to be cash equivalents. As of the consolidated balance sheet date and periodically throughout the year, balances of cash exceeded the federally insured limit. As of December 31, 2023 and December 31, 2022 the Company held no cash equivalents.

Oil and Gas Properties

The Company follows the successful efforts method of accounting for oil and gas activities. Under this method of accounting, costs associated with the acquisition, drilling, and equipping of successful exploratory wells and costs of successful and unsuccessful development wells are capitalized and depleted, net of estimated salvage values, using the units-of-production method on the basis of a reasonable aggregation of properties within a common geological structural feature or stratigraphic condition, such as a reservoir or field. The Company’s proved oil and gas reserve information was computed by applying the average first-day-of-the-month oil and gas price during the 12-month period ended on the balance sheet date. During the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, the Company recorded depletion expense of $81.1 million, $63.3 million, $60.4 million and $5.4 million, respectively. The Company’s depletion rate per BOE for the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021 was $18.68, $16.71, $16.73 and $16.97, respectively.

Exploration, geological and geophysical costs, delay rentals, and drilling costs of unsuccessful exploratory wells are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units-of-production amortization rate. A gain or loss is recognized for all other sales of proved properties.

Costs associated with unevaluated exploratory wells are excluded from the depletable base until the determination of proved reserves, at which time those costs are reclassified to proved oil and gas properties and subject to depletion. If it is determined that the exploratory well costs were not successful in establishing proved reserves, such costs are expensed at the time of such determination.

The Company reviews its oil and gas properties for impairment whenever events and circumstances indicate a decline in the recoverability of their carrying value. The Company estimates the expected future cash flows of its oil and gas properties and compares such cash flows to the carrying amount of the proved oil and gas properties to determine if the amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust its proved oil and gas properties to estimated fair value. The factors used to estimate fair value include estimates of reserves, future commodity prices adjusted for basis differentials, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the projected cash flows. The discount rate is a rate that management believes is representative of current market conditions and includes estimates for a risk premium and other operational risks. There were no proved oil and gas property impairments during the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021.

Asset Retirement Obligations (AROs)

AROs relate to estimated plugging and abandonment costs of oil and gas properties, including facilities, and the reclamation of the Company's well locations. The Company records the fair value of an ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes an estimated cost by increasing the carrying amount of proved oil and gas properties. Over time, the liability is accreted each period toward an estimated future cost, and the capitalized cost is depleted. The Company uses the income valuation technique to estimate the fair value of AROs using the amounts and timing of expected future dismantlement costs, credit-adjusted risk-free rates, and the time value of money. For business combinations, the valuation utilizes a discount rate commensurate with what a market participant would use for AROs recorded. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives or if federal or state regulators enact new requirements regarding the abandonment of wells. Adjustments to the liability are made as these estimates change. Upon settlement of the liability, the Company reports a gain or loss to the extent the actual costs differ from the recorded liability.

Equity-Based Compensation

The Company recognizes equity-based compensation expense associated with its long-term incentive plan ("LTIP") awards using the straight-line method over the requisite service period, which is generally the vesting period of the award except when provisions are present that accelerate vesting, based on their grant date fair values. The Company has elected to account for forfeitures of equity awards as they occur.

Predecessor Equity-Based Compensation

In 2020, the Predecessor amended its Limited Liability Company Agreement (the "Predecessor Company Agreement") which modified certain terms and conditions related to management incentive units ("MIUs") (see Note 12) and common units held by the founding members of management. The Predecessor accounted for MIUs granted to employees (which excludes the founding members of management) as liability awards under accounting guidance related to share-based compensation, whereby vested awards are recognized as liabilities, with changes in the estimated value of the awards recorded in earnings, until the holders have borne the risk of unit ownership, at which point the liability associated with the employee MIUs is reclassified to temporary equity, and changes in the estimated value of the employee MIUs are recorded as an adjustment to members' equity.

Equity-based compensation was also recognized for in-substance call options granted to the founding members of management which were classified as liabilities, recorded at estimated fair market value at each period end. Changes in the estimated fair value were recorded in earnings. As the Predecessor was a private entity whose units were not traded, we considered the average volatility of comparable entities to develop an estimate of expected volatility which resulted in a reasonable estimate of fair value. Refer to Note 12 for further information regarding these awards.

Revenue Recognition

The Company's revenue is derived from the sale of its produced oil and natural gas from wells in which the Company has non-operated revenue or royalty interests. The Company's oil and natural gas are produced and sold primarily in the core of the Williston Basin in North Dakota and Montana.

The sales of produced oil and natural gas are made under contracts that the operators of the wells have negotiated with customers, which typically include variable consideration based on monthly pricing tied to local indices and volumes delivered. Revenue is recorded at the point in time when control of the produced oil and natural gas transfers to the customer. Statements and payment may not be received via the operator of the wells for one to six months after the date the produced oil and natural gas is delivered, and, as a result, the amount of production delivered to the customer and the price that will be received for the sale of the product is estimated utilizing production reports, market indices, and estimated differentials. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated, and revenue due to the Company is recorded within revenue receivable in the accompanying balance sheets until payment is received. Differences between the estimated amounts and the actual amounts received from the sale of the produced oil and natural gas are recorded when known, which is generally when statements and payment are received. Such differences have historically been immaterial.

For the oil and natural gas produced from wells in which the Company has non-operated revenue or royalty interests, the Company recognizes revenue based on the details included in the statements received from the operator. Any gathering, transportation, processing, production taxes, and other deductions included on the statements are recorded based on the information provided by the operator. The Company does not disclose the value of unsatisfied performance obligations as it applies the practical exemption which applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Concentrations of Credit Risk

For the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, three, four, three and three operators accounted for 49 percent, 54 percent, 37 percent and 42 percent, respectively, of oil and natural gas revenue. As of December 31, 2023 and December 31, 2022, three and four operators accounted for 56 percent and 65 percent, respectively, of oil and natural gas revenue receivable. The Company's oil and natural gas revenue receivable is generated from the sale of oil and natural gas by operators on its behalf. The Company monitors the financial condition of its operators.

Income Taxes

Income taxes are provided for the tax effects of transactions reported in the financial statements and consist of taxes currently payable plus deferred income taxes related to certain income and expenses recognized in different periods for financial and income tax reporting purposes. Deferred income tax liabilities represent the future income tax consequences of those differences, which will be taxable when liabilities are settled. Deferred income taxes may also include tax credits and net operating losses that are available to offset future income taxes. Deferred income taxes are measured by applying currently enacted tax rates.

The Company accounts for uncertainty in income taxes for tax positions taken or expected to be taken in a tax return. Only tax positions that meet the more-likely-than-not recognition threshold are recognized. The Company does not have any uncertain tax positions recorded as of December 31, 2023.

The Predecessor and Vitesse Oil were limited liability companies that passed tax liability through to its members and accordingly did not record income tax expense.

Deferred Finance Charges

Costs associated with the revolving credit facility are deferred and amortized to interest expense over the term of the related financing. The amount of deferred financing costs incurred, and the amortization of deferred financing costs, was immaterial for all periods presented.

Derivative Financial Instruments

The Company enters into derivative contracts to manage its exposure to oil and gas price volatility. Commodity derivative contracts may take the form of swaps, puts, calls, or collars. Cash settlements from the Company's commodity price risk management activities are recorded in the month the contracts mature. Any realized gains and losses on settled derivatives, as well as mark-to-market gains or losses, are aggregated and recorded to Commodity derivative (loss) gain, net on the consolidated statements of operations.

GAAP requires recognition of all derivative instruments on the consolidated balance sheets as either assets or liabilities measured at fair value. Subsequent changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Gains and losses on derivative hedging instruments must be recorded in either other comprehensive income or current earnings, depending on the nature and designation of the instrument. The Company has elected to not designate any derivative instruments as accounting hedges, and therefore marks all commodity derivative instruments to fair value and records changes in fair value in earnings. Amounts associated with deferred premiums on derivative instruments are recorded as a component of the derivatives' fair values (see Note 6).

New Accounting Pronouncements

In June 2016, FASB issued ASU No. 2016-13, Financial Instruments—Credit Losses: Measurement of Credit Losses on Financial Instruments. The ASU includes changes to the accounting and measurement of financial assets requiring the Company to recognize an allowance for all expected credit related losses over the life of the financial asset at origination. This is different from the current practice, where an allowance is not recognized until the losses are considered probable. The new guidance was effective for the Company on January 1, 2023. Upon adoption, the ASU was applied using a modified retrospective transition method to the beginning of the earliest period in which the new guidance is effective. The adoption of the new guidance did not have a material impact on the Company's financial statements and related disclosures.

In November 2023, FASB issued ASU No. 2023-07, Improvements to Reportable Segment Disclosures. The ASU updates reportable segment disclosure requirements primarily through enhanced disclosures about significant segment expenses. The new guidance will be effective for the Company's year ending December 31, 2024. The Company does not believe the new guidance will have a material impact on its consolidated financial statements and related disclosures.

In December 2023, FASB issued ASU 2023-09, Improvements to Income Tax Disclosures. The ASU establishes new income tax disclosure requirements in addition to modifying and eliminating certain existing requirements. The guidance will be applied on a prospective basis with the option to apply the standard retrospectively. The new guidance will be effective for the Company's year ending December 31, 2025. The Company does not believe the new guidance will have a material impact on its consolidated financial statements and related disclosures.

Note 3—Asset Acquisitions

During the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, the Company purchased a number of proved oil and gas properties and proved leaseholds for an aggregate purchase price of $35.7 million, $28.5 million, $6.2 million, and $0.1 million, respectively. In addition, as part of the Spin-Off during the year ended December 31, 2023, $35.6 million of oil and gas properties and $5.0 million of net liabilities of Vitesse Oil were contributed in exchange for 2,120,312 shares of common stock of the Company for total consideration of $30.6 million.

The transactions qualified as asset acquisitions; therefore, the oil and gas properties were recorded based on the fair value of the total consideration transferred on the acquisition dates, and transaction costs were capitalized as a component of the assets acquired. Transaction costs during the years ended December 31, 2023, December 31, 2022 and November 30, 2021 and the month ended December 31, 2021 were immaterial. The purpose of the acquisitions was to acquire proved developed and proved undeveloped oil and gas properties that were proximate and complementary to existing properties and leases for strategic purposes.

Note 4—Fair Value Measurements

Accounting standards require certain assets and liabilities be reported at fair value in the consolidated financial statements and provide a framework for establishing that fair value. The framework for determining fair value is based on a hierarchy that prioritizes the inputs and valuation techniques used to measure fair value.

Fair values determined by Level 1 inputs use quoted prices in active markets for identical assets or liabilities that the Company has the ability to access.

Fair values determined by Level 2 inputs use other inputs that are observable, either directly or indirectly. These Level 2 inputs include quoted prices for similar assets and liabilities in active markets and other inputs, such as interest rates, yield curves, and forward commodity price curves, that are observable at commonly quoted intervals.

Level 3 inputs are unobservable inputs, including inputs that are available in situations where there is little, if any, market activity for the related asset or liability. These Level 3 fair value measurements are based primarily on management's own estimates using pricing models, discounted cash flow methodologies, or similar techniques taking into account the characteristics of the asset or liability. Significant Level 3 inputs include estimated future cash flows used in determining the fair value of purchased oil and gas properties.

In instances where inputs used to measure fair value fall into different levels in the above fair value hierarchy, fair value measurements in their entirety are categorized based on the lowest level input that is significant to the valuation. The Company's assessment of the significance of particular inputs to these fair value measurements requires judgment and considers factors specific to each asset or liability.

Recurring Fair Value Measurements

As of December 31, 2023, the Company's derivative financial instruments are composed of commodity swaps. The fair value of the swap agreements is determined under the income valuation technique using a discounted cash flow model. The fair values of options are determined under the income valuation technique using an option pricing model along with the stated amount of deferred premiums if applicable. The valuation models require a variety of inputs, including contractual terms, published forward commodity prices, volatilities for options, and discount rates, as appropriate. The Company's estimates of fair value of derivatives include consideration of the counterparty's creditworthiness, the Company's creditworthiness, and the time value of money. The consideration of these factors results in an estimated exit price for each derivative asset or liability under a marketplace participant's view. All of the significant inputs are observable, either directly or indirectly; therefore, the Company's commodity derivative instruments are included within Level 2 of the fair value hierarchy (see Note 6).

Nonrecurring Fair Value Measurements

Nonrecurring measurements include the fair value of impaired proved oil and gas properties. The Company determines the estimated fair value of the impaired proved oil and gas properties by using a discounted cash flow approach with unobservable Level 3 inputs (see Note 2) at the time of impairment.

The Company uses the income valuation technique to estimate the fair value of asset retirement obligations, at initial recognition, arising from the development of proved properties using the amounts and timing of expected future dismantlement costs and credit-adjusted risk-free rates. Accordingly, the fair value is based on unobservable inputs and, therefore, is included within Level 3 of the fair value hierarchy. The significant unobservable inputs include the gross cost of abandoning oil and gas wells; the economic lives of the properties; the inflation rate; and the credit-adjusted risk-free rate of the Company.

Financial Instruments Not Measured at Fair Value

The carrying amounts of the majority of the Company's financial instruments, namely cash, receivables, accounts payable, and accrued liabilities, approximate their fair values due to the short-term nature of these instruments. The Company's credit facility (see Note 5) has a recorded value that approximates fair market value, as it bears interest at a floating rate that approximates a current market rate.

Note 5—Credit Facility

Revolving Credit Facility

In connection with the Spin-Off in January 2023, the Company entered into a secured revolving credit facility with Wells Fargo Bank, N.A., as administrative agent, and a syndicate of banks, as lenders (the "Revolving Credit Facility"). The Revolving Credit Facility amends and restates the revolving credit facility of the Predecessor (the "Prior Revolving Credit Facility"). The Predecessor, as predecessor borrower under the Predecessor Revolving Credit Facility, assigned the liens and existing rights, liabilities and obligations under the Prior Revolving Credit Facility to the Company pursuant to the Revolving Credit Facility. The Revolving Credit Facility will mature on April 29, 2026. The Revolving Credit Facility permits borrowing on a revolving credit basis with availability equal to the least of (1) the aggregate elected commitments, (2) the borrowing base and (3) the maximum credit amount of $500.0 million. The borrowing base under the Revolving Credit Facility is subject to regular, semi-annual redeterminations on or about April 1 and October 1 of each year based on, among other things, the value of the Company's proved oil and natural gas reserves, as determined by the lenders in their discretion. As of December 31, 2023, the Company's borrowing base was $245.0 million with an aggregate elected commitment of $180.0 million of which $81.0 million was outstanding.

At the Company's option, borrowings under the Revolving Credit Facility bear interest at a rate unchanged from the Predecessor Revolving Credit Facility, which is either an adjusted forward-looking term rate based on SOFR ("Term SOFR") or an adjusted base rate ("Base Rate") (the highest of the administrative agent's prime rate, the federal funds rate plus 0.50% or the 30-day Term SOFR rate plus 1.0%), plus an applicable margin expected to range from 1.75% to 2.75% with respect to Base Rate borrowings and 2.75% to 3.75% with respect to Term SOFR borrowings, in each case based on the current commitment utilization percentage. Interest is calculated and paid monthly in arrears. Additionally, the Company incurs an unused credit facility fee, paid quarterly, of 0.50% of the unutilized commitment regardless of the borrowing base utilization percentage. As of December 31, 2023, the interest rate on the outstanding balance under the Revolving Credit Facility was 8.46%.

Consistent with the Prior Revolving Credit Facility, the Revolving Credit Facility is guaranteed by all of the Company's subsidiaries and is collateralized by a first priority lien on substantially all assets of Vitesse and its subsidiaries, including a first priority lien on properties representing a minimum of 85% of the total present value of the Company's proved oil and natural gas properties.

The Revolving Credit Facility contains various affirmative, negative and financial maintenance covenants. These covenants limit the Company's ability to, among other things, incur or guarantee additional debt, make distributions to equity holders, make certain investments and acquisitions, incur certain liens or permit them to exist, enter into certain types of transactions with affiliates, merge or consolidate with another company and transfer, sell or otherwise dispose of assets.

Under the Revolving Credit Facility, the Company is permitted to make cash distributions without limit to our equity holders if (i) no event of default or borrowing base deficiency (i.e., outstanding debt (including loans and letters of credit) exceeds the borrowing base) then exists or would result from such distribution and (ii) after giving effect to such distribution, (a) total outstanding credit usage does not exceed 80% of the least of (the following collectively referred to as "Commitments"): (1)$500.0 million (2) then effective borrowing base, and (3) the then-effective aggregate amount of the aggregate elected commitments and (b) as of the date of such distribution, the EBITDAX Ratio does not exceed 1.50 to 1.00. If the EBITDAX Ratio does not exceed 2.25 to 1.00, and if total outstanding credit usage does not exceed 80% of the Commitments, the Company may also make distributions if free cash flow (as defined under the Revolving Credit Facility) is greater than $0 and the Company has delivered a certificate to lenders attesting to the foregoing.

The Revolving Credit Facility contains covenants requiring us to maintain the following financial ratios tested on a quarterly basis (terms below are as defined in the Revolving Credit Facility): (1) a consolidated Total Funded Debt to consolidated EBITDAX ratio of not greater than 3.0 to 1.0; and (2) a ratio of consolidated current assets to consolidated current liabilities of not less than 1.0 to 1.0. These financial covenants are consistent with the Predecessor Revolving Credit Facility. The Revolving Credit Facility also contains covenants that require that the Company enter into swap agreements covering not less than 40% of reasonably anticipated PDP production for the following four quarters when the Utilization Percentage, as defined in the Revolving Credit Facility, is less than 50% and covering at least 50% of reasonably anticipated PDP production for the following eight quarters if the Utilization Percentage is 50% or greater. The Revolving Credit Facility contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross default, bankruptcy and change in control. If an event of default exists under the Revolving Credit Facility, the lenders will be able to terminate the lending commitments, accelerate the maturity of the Revolving Credit Facility and exercise other rights and remedies with respect to the collateral. The Company was in compliance with all financial covenants of the Revolving Credit Facility at December 31, 2023.

On May 2, 2023, the Company entered into an amendment to the Revolving Credit Facility in conjunction with the regular semi-annual borrowing base redetermination that reduced the borrowing base to $245 million (primarily related to lower commodity prices), reaffirmed elected commitments at $170 million and reduced hedging requirements in certain circumstances, among other items. On November 3, 2023, in conjunction with the regular semi-annual borrowing base redetermination, the Company's borrowing based was reaffirmed and the elected commitments were increased to $180 million.

On January 17, 2024, the Company entered into an amendment to the Revolving Credit Facility that increased the elected commitments to $210 million and added a fifth lender to the syndicate of banks.

Prior Revolving Credit Facility

In May 2015, the Predecessor entered into a credit facility with a syndicate of banks as lenders led by Wells Fargo Bank, N.A. as the administrative agent with the Predecessor as the borrower, which originally matured in May 2020. The Prior Revolving Credit Facility was subsequently amended, and the maturity date was extended to April 2026. The most recent amendment was executed in April 2022 (the "April 2022 amendment"). The Prior Revolving Credit Facility specified an aggregate maximum credit amount equal to $500.0 million and a maximum borrowing base, as determined by the lenders. The determination of the borrowing base took into consideration the estimated value of the Predecessor's oil and gas properties in accordance with the lenders' customary practices for oil and gas loans. The borrowing base was subject to scheduled redeterminations on a semiannual basis. The amount available for borrowing could be increased or decreased as a result of such redeterminations. As of December 31, 2022, the borrowing base under the Prior Revolving Credit Facility was $200.0 million with an elected commitment of $170.0 million of which $48.0 million was outstanding.

Prior to the April 2022 amendment, the Predecessor had the option to request borrowings under either a eurodollar loan or an alternative base rate loan. Eurodollar loans bore interest at the adjusted LIBOR plus an applicable margin ranging from 2.75% to 3.75% depending on the borrowing base utilization percentage. Alternative base rate loans bore interest at the higher of (a) the prime rate in effect on such day, (b) the federal funds effective rate in effect on such day plus 0.50%, or (c) the adjusted LIBOR for a one-month interest period on such day plus an applicable margin ranging from 1.75% to 2.75% depending on the borrowing base utilization percentage. With the April 2022 amendment, at the Predecessor's option, borrowings under the Prior Revolving Credit Facility bore interest at either an adjusted forward-looking term rate based on the Secured Overnight Financing Rate ("SOFR") or an adjusted base rate ("Predecessor Base Rate") (the highest of the administrative agent's prime rate, the Federal Funds rate plus 0.50% or the 30-day SOFR rate plus 1.0%), plus a spread ranging from 1.75% to 2.75% with respect to Predecessor Base Rate borrowings and 2.75% to 3.75% with respect to SOFR borrowings, in each case based on the borrowing base utilization percentage. Interest was calculated and paid monthly in arrears. Additionally, the Predecessor incurred an unused credit facility fee of 0.50% regardless of the borrowing base utilization percentage. As of December 31, 2022, the interest rate on the outstanding balance under the Prior Revolving Credit Facility was 7.42%.

Note 6—Derivative Instruments

The Company periodically enters into various commodity hedging instruments to mitigate a portion of the effect of oil and natural gas price fluctuations. The Company classifies the fair value amounts of commodity derivative assets and liabilities as current or noncurrent commodity derivative assets or current or noncurrent commodity derivative liabilities, whichever the case may be.

The following table summarizes the location and fair value amounts of commodity derivative instruments in the consolidated balance sheet as of December 31, 2023, as well as the gross recognized derivative assets, liabilities, and amounts offset in the consolidated balance sheet:

(in thousands)	GROSS RECOGNIZED FAIR VALUE ASSETS/ LIABILITIES	GROSS AMOUNTS OFFSET	NET RECOGNIZED FAIR VALUE ASSETS/ LIABILITIES
Commodity derivative assets:			
Current derivative assets	$ 10,038	$ —	$ 10,038
Noncurrent derivative assets	1,109	—	1,109
Total	$ 11,147	$ —	$ 11,147
Commodity derivative liabilities:			
Current derivative liabilities	$ —	$ —	$ —
Noncurrent derivative liabilities	—	—	—
Total	$ —	$ —	$ —

The following table summarizes the location and fair value amounts of all commodity derivative instruments in the consolidated balance sheet as of December 31, 2022, as well as the gross recognized derivative assets, liabilities, and amounts offset in the consolidated balance sheet:

(in thousands)	GROSS RECOGNIZED FAIR VALUE ASSETS/ LIABILITIES	GROSS AMOUNTS OFFSET	NET RECOGNIZED FAIR VALUE ASSETS/ LIABILITIES
Commodity derivative assets:			
Current derivative assets	$ 2,856	$ (744)	$ 2,112
Noncurrent derivative assets	1,721	(566)	1,155
Total	$ 4,577	$ (1,310)	$ 3,267
Commodity derivative liabilities:			
Current derivative liabilities	$ 4,183	$ (744)	$ 3,439
Noncurrent derivative liabilities	566	(566)	—
Total	$ 4,749	$ (1,310)	$ 3,439

As of December 31, 2023, the Company had the following crude oil swaps:

INDEX	SETTLEMENT PERIOD	VOLUME HEDGED (Bbls)	WEIGHTED AVERAGE ROUNDED FIXED PRICE
WTI-NYMEX	Q1 2024	402,498	$ 79
WTI-NYMEX	Q2 2024	382,500	79
WTI-NYMEX	Q3 2024	327,500	79
WTI-NYMEX	Q4 2024	262,500	79
WTI-NYMEX	Q1 2025	90,000	75
WTI-NYMEX	Q2 2025	90,000	75

Due to the volatility of oil prices, the estimated fair values of the Company's commodity derivative instruments are subject to large fluctuations from period to period.

The counterparties in the Company's derivative instruments also participate in the Company's Credit Facility; accordingly, the Company is not required to post collateral, as the counterparties have the right of offset for any derivative liabilities, and the Credit Facility is secured by the Company's oil and gas assets. For further discussion related to the fair value of the Company's derivatives, see Note 4.

Note 7—Accrued Liabilities

Accrued liabilities at December 31, 2023 and December 31, 2022 are summarized as follows:

	DECEMBER 31,	
(in thousands)	**2023**	**2022**
Accrued capital expenditures	$ 22,800	$ 15,500
Accrued lease operating expenses, net	3,258	2,740
Accrued compensation	3,647	3,524
Accrued derivative settlement	—	189
Other accrued liabilities	2,802	1,068
Accrued spin related expenditures	—	2,828
Total	$ 32,507	$ 25,849

Note 8—Asset Retirement Obligations

A rollforward of AROs for the years ended December 31, 2023 and December 31, 2022 are presented below.

	DECEMBER 31,	
(in thousands)	**2023**	**2022**
Balance—Beginning of period	$ 6,823	$ 6,156
Liabilities incurred	951	347
Accretion expense	579	320
Revisions	—	—
Balance—End of year	$ 8,353	$ 6,823

Note 9—Related Party Transactions

3B acquired common units in the Predecessor which were funded by two Initial Loans with related parties. As part of the funding of the Predecessor, 3B entered into two different promissory notes with VE Holding LLC, an entity owned by JFG. The promissory notes allowed 3B to borrow up to $7.875 million and $3.5 million, initially accruing interest at 10.0 percent and 3.5 percent, respectively, and had maturity dates of May 7, 2021 (the "Initial Loans"). Initially, repayment of the $3.5 million promissory note was fully guaranteed by one of the members of 3B. Each of the two Initial Loans were collateralized by all of the common units held by 3B. In 2021, the $3.5 million promissory note was amended to remove the guarantee, change the interest rate to 10.0 percent and extend the maturity date to December 31, 2023. At the same time the $7.875 million promissory note was amended to extend the maturity date to December 31, 2023. The Initial Loans between 3B and VE Holding LLC were held outside of the Predecessor and were not a liability of the Predecessor. During 2022, there were $36.0 million of ratable distributions made to the common unit holders. The 3B distribution of $0.9 million was used to pay down a pro rata portion of the outstanding interest on the Initial Loans. The 3B common units and related loans were liquidated and terminated in connection with the Spin-Off.

In connection with the Predecessor Company Agreement, in July 2018 certain executives entered into two separate promissory notes aggregating to $10.0 million with VE Holding LLC (the "2018 Notes"), which are collateralized by MIUs granted to the respective executive. The 2018 Notes accrued interest at 3.0 percent per annum payable annually on December 31 and matured the earlier of July 1, 2024, an MIU exchange, or an acceleration event. The 2018 Notes could have been prepaid at any time but were subject to mandatory prepayment upon the issuance of any distributions from the Predecessor related to the MIUs held by such executives. Additionally, the 2018 Notes were considered full recourse to each respective executive for a limited time, with such recourse reduced by one-third each December 31 through 2020. As the 2018 Notes were between VE Holding LLC and the executives, they did not represent liabilities of the Predecessor. The Founder MIUs and related promissory notes were liquidated and terminated in connection with the Spin-Off.

The Predecessor entered into an amended and restated services agreement (the "Services Agreement") by and between the Predecessor, Vitesse Management, and Vitesse Oil, LLC ("Vitesse Oil") on May 7, 2014. Vitesse Oil was an entity with management common to that of the Predecessor. Per the Services Agreement, costs incurred by Vitesse Management were allocable between the Predecessor and Vitesse Oil initially at 50 percent each and adjusted automatically each quarter, such that the Predecessor's share of allocable costs were the greater of 50 percent or the quotient of the total contributed capital to the Predecessor made by its members and the sum of the total contributed capital to the Predecessor and Vitesse Oil by their respective members. As such, the Predecessor incurred 90 percent of the Vitesse Management costs for the years ended December 31, 2022, and November 30, 2021 and the month ended December 31, 2021. The amount of costs reimbursed from Vitesse Oil to the Predecessor for management services was $1.1 million, $1.1 million, and $0.1 million for each of the years ended December 31, 2022, and November 30, 2021 and the month ended December 31, 2021, respectively. The amount due to the Predecessor from Vitesse Oil as of December 31, 2022 was immaterial. Vitesse Oil was acquired as part of the Spin-Off and accordingly 100 percent of Vitesse Management costs were incurred by the Company subsequent to the Spin-Off.

On July 1, 2016, the Predecessor entered into a separate services agreement with Vitesse Management and JETX Energy, LLC ("JETX"), formerly known as Juneau Energy, LLC, another entity owned by JFG with common management. Per this services agreement, Vitesse Management is to provide JETX certain administrative services and supervise, administer, and manage the business affairs and operations of JETX and its subsidiaries for a service provider fee of $0.2 million per month. The term of this service agreement extends for an unlimited amount of time; however, it is subject to termination by either Vitesse Management or JETX if provided written consent following the first anniversary or a final exit event. During each of the years ended December 31, 2023, December 31, 2022, and November 30, 2021 and the month ended December 31, 2021, the Company recorded its net share of fees from JETX of approximately $2.7 million, $2.4 million, $2.4 million and $0.2 million, respectively, which is classified as a reduction to general and administrative expenses on the accompanying consolidated statements of operations.

On July 1, 2016, the Predecessor implemented the Employee Participation Plan ("EPP") pursuant to which employees, consultants, or independent contractors of the Predecessor were invited to personally acquire a working interest in new oil and gas wells in which the Predecessor elected to participate. The EPP was subsequently amended on January 1, 2018. The tranches were not to exceed a maximum of $2.0 million of capital expenditures in the aggregate for each year. Participants in the EPP were required to fund their proportion of development costs and ongoing operating expenses of those specific wellbores. Compensation expense was measured by the allocable amount of the value of the assigned wellbore leasehold costs which was historically immaterial. On November 30, 2022, the Predecessor repurchased the outstanding EPP working interest for $4.9 million in accordance with the terms of the plan and terminated the EPP.

Note 10—Leases

The Company is obligated under noncancelable leases primarily for facilities. Total expense under these operating leases was $0.4 million, $0.4 million, $0.4 million and immaterial for the years ended December 31, 2023, December 31, 2022, and November 30, 2021 and the month ended December 31, 2021, respectively.

Leases with an initial term of 12 months or less are not recorded on the consolidated balance sheets.

The Company's lease agreements do not provide an implicit borrowing rate; therefore, an internal incremental borrowing rate is determined based on information available at the lease commencement date for the purpose of determining the present value of lease payments. The right-of-use assets of $0.2 million and $0.2 million as of December 31, 2023 and 2022, respectively, are recorded within Other noncurrent assets on the consolidated balance sheets. The related lease obligations of $0.2 million and $0.2 million as of December 31, 2023 and 2022, respectively, are recorded within Other current liabilities on the consolidated balance sheets.

The Company entered into an agreement in December 2022 to lease office space in Greenwood Village, CO to be its future principal executive office space. The lessor is required to complete certain agreed upon tenant improvements and the lease is scheduled to commence when construction of the asset is completed in 2024.

Note 11—Commitments and Contingencies

Litigation

From time to time, the Company may be involved in litigation relating to claims arising out of its operations in the normal course of business. As of the date of this report, management of the Company was unaware of any material legal proceedings against the Company. The Company maintains insurance to cover certain actions.

Note 12—Equity

Authorized Capital Stock

The Amended and Restated Certificate of Incorporation authorized capital stock consisting of 95,000,000 shares of common stock, par value $0.01 per share and 5,000,000 shares of preferred stock, par value $0.01 per share.

Common Stock

During the year ended December 31, 2023 the following transactions related to our common stock occurred:

- 3B transferred all of its Predecessor equity interests to JFG as repayment for the Initial Loans;
- JFG distributed the remaining Predecessor equity interests to its shareholders in the Spin-Off, which amounted to 25,628,162 shares of common stock in the Company;
- the Transitional Equity Award Adjustment Plan (the "Transitional Plan"), as discussed further below, was implemented and resulted in the following issuances to current and former directors and employees of JFG:

    - 286,729 restricted stock awards (included in issuance of common stock in exchange for Vitesse Energy, LLC on the Consolidated Statements of Equity), of which 56,218 were issued as common shares during the period;
    - 1,475,613 restricted stock units, of which 810,507 were issued as common shares during the period, net of shares cashed out as fractional unit;
- Predecessor MIUs granted to Predecessor employees other than the Predecessor's two founders were exchanged for 163,544 shares of common stock;
- Vitesse Oil was contributed in exchange for 2,120,312 common shares;
- 3,152,247 restricted stock units were issued, net of forfeitures, to officers, directors and employees;
- 14,600 shares of common stock were repurchased and retired as part of our Stock Repurchase Program, as discussed further below.
- Declared dividends of $65.6 million, or $2.00 per share, on common stock during the period.

Preferred Stock

Our Amended and Restated Certificate of Incorporation authorizes our board of directors to designate and issue from time to time one or more series of preferred stock without stockholder approval. Our board of directors may fix and determine the designation, relative rights, preferences and limitations of the shares of each such series of preferred stock. There are no present plans to issue any shares of preferred stock and there are currently no shares outstanding.

Long-Term Incentive Plan

The Company's long-term incentive plan ("LTIP") provides for the granting of various forms of equity-based awards, including stock option awards, stock appreciation rights awards, restricted stock awards, restricted stock unit awards, performance awards, cash awards and other stock-based awards to employees, directors and consultants of the Company. Under the LTIP, 3,960,000 shares were initially available to be awarded and as of December 31, 2023, there were 807,753 shares available to be granted.

The following is a summary of LTIP activity during the year ended December 31, 2023:

	Shares of restricted stock unit awards	Weighted-Average Price on Date of Grant
Outstanding at January 1, 2023	—	$ —
Granted	3,333,122	14.96
Vested	—	—
Forfeited	(180,875)	14.40
Outstanding at December 31, 2023	3,152,247	$ 14.99

For restricted stock units, the Company recognizes the grant date fair-value of awards over the requisite service period as stock-based compensation expense on a straight-line basis except when provisions are present that accelerate vesting. Restricted stock units are considered issued but not outstanding when granted. Accumulated accrued stock based compensation expense and any accrued dividends are reversed in the period when units are forfeited and the units are no longer considered issued.

During the year ended December 31, 2023, the Company recognized $32.2 million of equity-based compensation expense relating to these restricted stock units of which $26.8 million, or 1,863,000 restricted stock units, was for awards that had a retirement provision and were granted to retirement-eligible employees and therefore resulted in immediate recognition of expense.

As of December 31, 2023, there is $15.0 million of unrecognized equity-based compensation expense related to unvested restricted stock unit awards. The cost is expected to be recognized through January 2027, over a weighted-average period of 2.56 years.

Transitional Equity Award Adjustment Plan

JFG's outstanding compensatory equity awards were adjusted into equity incentive awards denominated in part in shares of Vitesse common stock in connection with the Spin-Off. All adjusted awards are subject to generally the same vesting, exercisability, expiration, settlement and other material terms and conditions as applied to the applicable original JFG award immediately before the Spin-Off, except that equity awards relating to our common stock were subject to accelerated vesting, exercisability and in some cases settlement in the event of a change in control of the Company. All of the Transitional Plan equity awards discussed below were granted by JFG and therefore do not result in any compensation cost to the Company.

Transitional Plan Options

Each JFG stock option that did not remain an option to purchase shares of only JFG common stock was converted into both a post-Spin-Off option to purchase shares of JFG common stock and an option to purchase shares of Vitesse common stock. The exercise price of such JFG stock option and the exercise price and number of shares subject to such Vitesse stock option was adjusted so that (i) the aggregate intrinsic value of such post-Spin-Off JFG stock option and Vitesse stock option immediately after the Spin-Off equals the aggregate intrinsic value of the JFG stock option as measured immediately before the Spin-Off and (ii) the aggregate exercise price of such post-Spin-Off JFG stock option and Vitesse stock option equals the aggregate exercise price of the JFG stock option immediately before the Spin-Off, subject to rounding. Upon completion of the Spin-Off, 457,866 options were granted and none were exercised during the year ended December 31, 2023. The intrinsic option value of the options was $5.9 million at December 31, 2023 and the maximum number of shares of common stock that could be issued under the plan is 457,866.

Transitional Plan Restricted Units

Each JFG restricted stock unit award and performance stock unit award (other than those that will remain awards denominated in shares of only JFG stock, which includes the portion of any performance stock unit award that may be earned above the designated target level), including any additional stock units accrued as a result of dividend equivalents, was adjusted by the grant of a Vitesse restricted stock unit award. Upon completion of the Spin-Off, restricted stock units were granted in respect of these JFG awards. These restricted stock unit awards are capped at 1,475,613 and at December 31, 2023 103,653 have a remaining performance, service or vesting condition to satisfy. These restricted stock unit awards generally accrue dividends declared on common stock but have deferred issuance dates through January 2, 2099. During the year ended December 31, 2023, 810,507 restricted stock units were released as common stock, net of shares cashed out as fractional units.

Transitional Plan Restricted Stock Awards

Holders of a JFG restricted stock award received 286,729 shares of our common stock upon completion of the Spin-Off, which shares are subject to the provisions of the Transitional Plan, including generally the same risk of forfeiture and other conditions as applied to the original JFG restricted stock award. These restricted stock awards have no remaining performance or service conditions to satisfy, or any other vesting condition, and are paid dividends on common stock as declared but have deferred issuance dates through September 28, 2029. During the year ended December 31, 2023, 56,218 restricted stock awards were released as common stock.

Year	Restricted stock units	Restricted stock awards	Total
2024	115,728	57,580	173,308
2025	93,580	17,262	110,842
2026	323,138	48,619	371,757
2027	837	54,269	55,106
Thereafter	131,823	52,781	184,604
Total	**665,106**	**230,511**	**895,617**

The Transitional Plan governs the terms and conditions of the new Vitesse awards issued as an adjustment to JFG awards at the effective time of the Spin-Off, but will not be used to make any grants following the Spin-Off.

Stock Repurchase Program

In February 2023, the Board approved a stock repurchase program authorizing the repurchase of up to $60 million of the Company's common stock.

Under the Stock Repurchase Program, we may repurchase shares of our common stock from time to time in open market transactions or such other means as will comply with applicable rules, regulations and contractual limitations. The Board of Directors may limit or terminate the Stock Repurchase Program at any time without prior notice. The extent to which the Company repurchases its shares of common stock, and the timing of such repurchases, will depend upon market conditions and other considerations as may be considered in the Company's sole discretion.

During the year ended December 31, 2023, the Company repurchased 14,600 shares for $0.2 million and the shares were subsequently retired.

Net Loss Per Common Share

The Company uses the two-class method of calculating earnings per share because certain of the Company's unvested LTIP RSUs qualify as participating securities.

Basic earnings per share amounts have been computed as (i) net income (loss) (ii) less distributed and undistributed earnings allocated to participating securities (iii) divided by the weighted average number of basic shares outstanding for the periods presented. Diluted earnings per share amounts have been computed as (i) basic net income attributable to common stockholders (ii) plus the adjustment of distributed and undistributed earnings allocated to participating securities (iii) divided by the weighted average number of diluted shares outstanding for the periods presented.

The components of basic and diluted net income (loss) per share attributable to common stockholders are as follows:

(in thousands except share and per share amounts)		FOR THE YEAR ENDED DECEMBER 31, 2023
Numerator for earnings per common share:		
Net (loss) attributable to Vitesse Energy, Inc.	$	(21,576)
Allocation of earnings to participating securities[(1)]		—
Net (loss) attributable to common shareholders	**$**	**(21,576)**
Adjustment to allocation of earnings to participating securities related to diluted shares		—
Net (loss) attributable to common shareholders for diluted EPS	**$**	**(21,576)**
Denominator for earnings per common share:		
Weighted average common shares outstanding - basic		28,741,995
Weighted average Transitional Share RSUs outstanding		814,972
Denominator for basic earnings per common share		**29,556,967**
LTIP RSUs		—
Transitional Share options		—
Denominator for diluted earnings per common share		**29,556,967**
Net (loss) per common share:		
Basic	**$**	**(0.73)**
Diluted	**$**	**(0.73)**
Shares excluded from diluted earnings per share due to anti-dilutive effect:		
LTIP RSUs		3,143,715
Transitional Share options		270,181
Transitional Share RSUs with remaining performance/service obligation		103,653

(1) Certain unvested LTIP RSUs represent participating securities because they participate in nonforfeitable dividends with the common equity holders of the Company. Participating earnings represent the distributed and undistributed earnings of the Company attributable to the participating securities. These unvested LTIP RSUs do not participate in undistributed net losses as they are not contractually obligated to do so.

Predecessor Members' Equity

The Predecessor had two classes of membership units, with the following units authorized, issued, and outstanding as of December 31, 2022:

	AUTHORIZED	ISSUED AND OUTSTANDING
Common units	450,000,000	450,000,000
Management incentive units	1,000,000	953,750

Common Units

Common units of the Predecessor were issued at $1 per unit, with an aggregate capital commitment from all common members of $450 million. There initially were five managers on the board of managers of the Predecessor, with three managers designated by JFG and two managers designated by 3B. For voting purposes, each manager was entitled to one vote, and the affirmative vote of a majority of the board of managers, including at least one JFG manager, was required to ratify any significant decisions.

Management Incentive Units

Predecessor MIUs were issued by the Predecessor to eligible employees and/or consultants. All MIUs were nonvoting and provided the MIU holders the opportunity to participate in distributions after the common unit holders received a specified return.

MIUs were granted to the two founding members of management ("Founder MIUs") and certain other employees of the Predecessor ("Non-Founder MIUs"). MIUs were subject to vesting requirements and forfeiture provisions specific to the Founder

MIUs and Non-Founder MIUs, as outlined in the Predecessor Company Agreement, employment agreement, grant letters, and other supporting MIU documentation.

The Predecessor accounted for Non-Founder MIUs as liability-based awards until the respective holder had borne the risk of unit ownership, at which point the value of the liability was reclassified outside of permanent equity. While the awards were classified as liabilities, compensation expense was recorded through the vesting period, and changes in the estimated fair market value of the liability, were recorded in earnings. Once reclassified outside of permanent equity increases in the estimated fair market value of the award were recorded through members' equity. During the years ended December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, the Predecessor recorded an increase of $1.5 million, a reduction of $1.5 million, and a reduction of $1.0 million respectively, through members' equity to adjust the Non-Founder MIUs to fair market value.

A summary of the Predecessor's activity related to Non-Founder MIUs for the years ended the years ended December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, is presented below:

	FOR THE YEAR ENDED DECEMBER 31,	FOR THE MONTH ENDED DECEMBER 31,	FOR THE YEAR ENDED NOVEMBER 30,
	2022	2021	2021
Nonvested at period end	28,750	45,000	45,000
Granted during the period	—	—	—
Vested during the period	16,250	—	37,500
Forfeited during the period	—	—	—
Fair value of MIUs vested during the period	$0.2 million	$ —	$ 0.7 million

As of December 31, 2022, there was no unrecognized compensation cost related to nonvested unit-based compensation arrangements.

As a result of each of the management founders' receipt of an in-substance nonrecourse note (see Note 9) that were each collateralized by all of the Founder MIUs held by the respective executive, for accounting purposes, the Predecessor granted each of the management founders an in-substance call option that is within the scope of accounting guidance related to share-based compensation (the "Founder MIU Option Grant"). Due to the nature and terms of the Founder MIU Put Option, the Founder MIU Option Grant was classified as a liability award, remeasured at fair market value at each reporting date with the change in fair market value recorded to earnings.

Total compensation cost (income) recognized in the consolidated statements of operations within Equity-based compensation for the years ended December 31, 2022 and November 30, 2021 and the month ended December 31, 2021 is as follows:

	FOR THE YEAR ENDED DECEMBER 31,	FOR THE MONTH ENDED DECEMBER 31,	FOR THE YEAR ENDED NOVEMBER 30,
(in thousands)	2022	2021	2021
Common Unit Option Grant	$ (2,089)	$ 383	$ (569)
Founder MIU Option Grant	(8,680)	2,170	1,625
Non-Founder MIUs	3	75	353
Total	$ (10,766)	$ 2,628	$ 1,409

As of December 31, 2022, the intrinsic value of the Founder MIU Option Grant and the Common Unit Option Grant was determined to be de minimis given the limited amount of time until the instruments were settled and prevailing economic factors. The Option Grants were forfeited on January 13, 2023 with the executives agreeing to settle their common units and Founder MIUs in exchange for JFG forgiving the 2018 Notes and any accrued interest. The December 31, 2022 liability and the factors considered in valuing the liability at December 31, 2022 are not presented due to the immaterial nature of these items.

Measurement of unit-based compensation

The Predecessor recorded the Non-Founder MIUs, Founder MIU Option Grant, and Common Unit Option Grant at fair value at the date of grant and at each balance sheet date, which results in compensation cost being measured at fair value. As noted above, vested Non-Founder MIUs, where the respective holder had borne the risk of ownership, are recorded within temporary equity, with changes in fair value recorded within members' equity.

The fair value of each of the Founder MIU Option Grant and the Common Unit Option Grant (collectively the "Options") were estimated using a Black Scholes Model. As the Predecessor did not have publicly-traded equity, it incorporated data from a group of publicly-traded peer companies when estimating fair value. Expected volatilities were based on the historical volatility of our identified peer group of companies. The expected term of the Options was determined based on the timing of an exit or liquidity event. The risk-free rate for periods within the expected life of the option was interpolated from the US constant maturity treasury rate, for a term corresponding to the expected term.

Founder MIU Option Grant	DECEMBER 31, 2021	NOVEMBER 30, 2021
Expected volatility	105% - 140%	125% - 170%
Weighted-average volatility	140%	150%
Expected dividends/distributions	0%	0%
Expected term (in years)	0.5	1
Risk-free rate	0.69%	0.24%

Common Unit Option Grant	DECEMBER 31, 2021	NOVEMBER 30, 2021
Expected volatility	55%	50%
Weighted-average volatility	50%	50%
Expected dividends/distributions	0%	0%
Expected term (in years)	0.5	1
Risk-free rate	0.69%	0.24%

Distributions

Distributions of funds associated with common units follow a prescribed framework, which is outlined in detail in the Predecessor Company Agreement. In general, distributions were first allocated to those unitholders based on their allocable share, as defined in the Predecessor Company Agreement. Each unitholder then received a distribution in accordance with the tiered waterfall, as defined in the Predecessor Company Agreement. The Company made $36.0 million, $12.0 million and $6.0 million of distributions on common units during the years ended December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, respectively.

Earnings Per Unit

The Predecessor had two classes of equity in the form of common units and MIUs that were vested and where the holder had borne the risks and rewards of ownership at which point the MIU was reclassified from liabilities to outside of permanent equity. Both common units and temporary equity classified MIUs were considered common units, and distributions were made in accordance with the Predecessor Company Agreement. As such, the Company presents earnings per unit ("EPU") for both classes of equity. In calculating EPU, we applied the two-class method. Under the two-class method net income (loss) attributable to common units is allocated to common units and other participating securities in proportion to the claim on earnings of each participating security after giving effect to distributions declared during the period, if any. The following table sets forth the computation of basic and diluted net income (loss) per unit:

	FOR THE YEAR ENDED DECEMBER 31, 2022	FOR THE MONTH ENDED DECEMBER 31, 2021	FOR THE YEAR ENDED NOVEMBER 30, 2021
Common Units			
Net income (loss)	118,903	(7,359)	18,114
less: income allocable to participating securities			
In-substance options on common units (Common Unit Option)	(3,006)	—	(458)
In-substance options on Founder MIUs (Founder MIU Option)	—	—	—
Non-Founder MIUs classified as temporary equity	—	—	—
Non-Founder MIUs classified as liabilities	—	—	—
Net income (loss) attributable to common unitholders	115,897	(7,359)	17,656
Weighted Average Common Units Outstanding (in 000s)	450,000	450,000	450,000
less: Common Units accounted for as in-substance options	(11,375)	(11,375)	(11,375)
Weighted Average Common Units Outstanding (in 000s)	438,625	438,625	438,625
Basic and Diluted EPU	$ 0.26	$ (0.02)	$ 0.04
Temporary Equity Classified MIUs			
Income allocable to Non-Founder MIUs classified as temporary equity	$ —	$ —	$ —
MIUs classified in temporary equity (in 000s)	250	234	234
Basic and Diluted EPU	$ —	$ —	$ —

Note 13—Income Taxes

Historically, Vitesse Energy and Vitesse Oil have been treated as partnerships for U.S. federal applicable state and local income tax purposes. As partnerships, Vitesse Energy and Vitesse Oil were not subject to U.S. federal and certain state and local income taxes, and any taxable income or loss generated by Vitesse Energy and Vitesse Oil was passed through to and included in the taxable income or loss of their members. Following the Spin-Off, the Company is now subject to U.S. federal and applicable state and local income taxes for taxable income or loss.

Income tax expenses and benefits included in the consolidated statements of operations are detailed below:

(in thousands)	FOR THE YEAR ENDED DECEMBER 31, 2023
Current taxes:	
Federal	$ —
State	—
Total current income tax benefit (expense)	$ —
Deferred taxes:	
Federal	$ (55,687)
State	(6,259)
Total deferred income tax benefit (expense)	$ (61,946)
Total income tax benefit (expense)	$ (61,946)

A reconciliation of the statutory federal income tax expense, which is calculated at the federal statutory rate of 21% for the year ended December 31, 2023 to the income tax expense from continuing operations provided for the periods presented, is as follows:

(in thousands)	FOR THE YEAR ENDED DECEMBER 31, 2023
Income tax benefit (expense) at the federal statutory rate	$ (8,862)
State income taxes benefit (expense) - net of federal income tax benefits	(1,801)
GAAP and tax differences of Predecessor	(44,118)
Equity-based compensation	(6,148)
Other	(1,017)
Total income tax benefit (expense)	$ (61,946)

The tax effects of temporary differences that give rise to significant positions of the deferred income tax assets and liabilities are presented below:

	FOR THE YEARS ENDED DECEMBER 31,	
(in thousands)	2023	2022
Deferred tax assets:		
Asset retirement obligations	$ 1,951	$ —
Net operating loss	1,414	—
Interest expense	905	—
Equity-based compensation	691	—
Accrued compensation	831	—
Other assets	874	—
Total deferred tax assets	$ 6,666	$ —
Deferred tax liabilities:		
Oil and gas properties	$ (68,391)	$ —
Derivatives	(2,604)	—
Total deferred tax liabilities	$ (70,995)	$ —
Valuation Allowance	$ —	$ —
Total deferred tax (liability) asset	$ (64,329)	$ —

For the year ended December 31, 2023 the Company recorded a federal and state tax expense of $61.9 million. During Q1 the Predecessor was contributed into Vitesse resulting in a change in tax status and the recording of a $44.1 million federal and state deferred tax expense. In addition, a $2.4 million deferred tax liability was recorded in 2023 related to the acquisition of Vitesse Oil. For the years ended December 31, 2022 and November 30, 2021 and the month ended December 31, 2021, the Predecessor and Vitesse Oil were limited liability companies that passed tax liability through to its members and accordingly did not record income tax expense or deferred tax assets and liabilities.

As of December 31, 2023, the Company had $6.1 million and $4.1 million of U.S. federal and state net operating loss carryovers, respectively, and did not have any U.S. federal or state net operating loss carryovers at December 31, 2022. Approximately $0.1 million of the state net operating loss carryovers expire in 2033.

The Company periodically assesses whether it is more-likely-than-not that it will generate sufficient taxable income to realize its deferred income tax assets. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years. Based on when the Company expects existing taxable differences to be realized, management determined that sufficient positive evidence exists as of December 31, 2023 to conclude that it is more-likely-than-not that all of its deferred tax assets will realized.

The calculation of the Company’s tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes are more-likely-than-not to be sustained upon the examination by the Internal Revenue Service or other taxing authority. As of December 31, 2023 and 2022, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months. Interest and penalties related to uncertain tax positions are reported in income tax expense.

The Company is subject to the following material taxing jurisdictions: United States, Colorado, Montana and North Dakota. As of December 31, 2023, the Company has no tax years under audit. The Company remains subject to examination for federal income taxes and state income taxes for tax year 2023. The Predecessor and Vitesse Oil remain subject to examination for federal income taxes and state income taxes for tax years 2020 through 2023, which could have an impact on the deferred tax liability at Spin-Off.

Note 14—Subsequent Events

Other than the above disclosure or other subsequent events disclosed elsewhere in the notes to the financial statements, there were no material subsequent events.

Supplemental Oil and Gas Information (Unaudited)

Oil and Natural Gas Exploration and Production Activities

Oil and natural gas sales reflect the market prices of net production sold or transferred with appropriate adjustments for any contractual provisions. Production expenses include lifting costs incurred to operate and maintain productive wells and related equipment including such costs as operating labor, repairs and maintenance, materials, supplies and fuel consumed. Production taxes include ad valorem and severance taxes. Depletion of crude oil and natural gas properties relates to capitalized costs incurred in acquisition, exploration, and development activities. Results of operations do not include interest expense and general corporate amounts. The results of operations for the Company's crude oil and natural gas production activities are provided in the Company's related consolidated statements of operations. Capitalized costs relating the Company's oil and natural gas producing activities as of December 31, 2023 and December 31, 2022 are provided in the Company's consolidated balance sheets.

Costs Incurred

The costs incurred in crude oil and natural gas acquisition, exploration and development activities are highlighted in the table below.

	FOR THE YEARS ENDED DECEMBER 31,		FOR THE MONTH ENDED DECEMBER 31,	FOR THE YEAR ENDED NOVEMBER 30,
(In thousands)	**2023**	**2022**	**2021**	**2021**
Costs Incurred for the Year:				
Proved Property Acquisition and Other	$ 78,058	$ 28,547	$ 117	$ 6,210
Development	104,569	63,284	3,015	36,769
Total	$ 182,627	$ 91,831	$ 3,132	$ 42,979

Oil and Natural Gas Reserve Data

The following tables present the Company's net proved crude oil and natural gas reserves as prepared by Cawley, and include changes as estimated by the Company's engineering staff. The Company emphasizes that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

	OIL (MBbl)	NATURAL GAS (MMcf)	MBoe
Proved Developed and Undeveloped Reserves at November 30, 2020	33,106	84,829	47,244
Revisions of Previous Estimates	(2,998)	(4,181)	(3,695)
Extensions, Discoveries and Other Additions	899	2,648	1,340
Acquisition of Reserves	959	1,793	1,258
Production	(2,436)	(7,065)	(3,614)
Proved Developed and Undeveloped Reserves at November 30, 2021	29,530	78,024	42,534
Revisions of Previous Estimates	80	231	119
Extensions, Discoveries and Other Additions	—	—	—
Acquisition of Reserves	7	8	8
Production	(220)	(582)	(317)
Proved Developed and Undeveloped Reserves at December 31, 2021	29,397	77,681	42,344
Revisions of Previous Estimates	(100)	1,959	226
Extensions, Discoveries and Other Additions	1,419	2,561	1,846
Acquisition of Reserves	2,304	5,187	3,168
Production	(2,575)	(7,274)	(3,787)
Proved Developed and Undeveloped Reserves at December 31, 2022	30,445	80,114	43,797
Revisions of Previous Estimates	(5,735)	(7,027)	(6,906)
Extensions, Discoveries and Other Additions	3,141	5,826	4,112
Acquisition of Reserves	2,860	6,429	3,932
Production	(2,968)	(8,232)	(4,340)
Proved Developed and Undeveloped Reserves at December 31, 2023	27,743	77,110	40,595

	OIL (MBbl)	NATURAL GAS (MMcf)	MBoe
Proved Developed Reserves:			
November 30, 2020	17,841	47,418	25,744
November 30, 2021	17,764	58,437	27,504
December 31, 2021	17,612	58,058	27,288
December 31, 2022	17,290	58,897	27,106
December 31, 2023	18,440	60,202	28,474
Proved Undeveloped Reserves:			
November 30, 2020	15,265	37,410	21,500
November 30, 2021	11,765	19,586	15,030
December 31, 2021	11,785	19,623	15,055
December 31, 2022	13,155	21,217	16,691
December 31, 2023	9,303	16,907	12,121

Proved reserves are estimated quantities of crude oil and natural gas, which geological and engineering data indicate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are included for reserves for which there is a high degree of confidence in their recoverability and they are scheduled to be drilled within the next five years.

Notable changes in proved reserves for the year ended December 31, 2023 included the following:

- *Acquisitions:* We acquired 3,932 MBoe of proved undeveloped reserves in the Williston Basin and Central Rockies during 2023 (See Note 3).
- *Revisions to previous estimates:* In 2023, revisions to previous estimates decreased proved reserves by a net amount of 6,906 MBoe. These revisions were primarily attributable to the reclassification of undeveloped drilling locations totaling 4,184 MBoe of proved reserves from proved to non-proved and were made proactively as a result of lower-than-expected rig activity in the Williston Basin during the year and continued compliance with the SEC 5-year development

rule. In addition, the revisions included decreases in proved reserves of 1,072 MBoe related to forecast/timing/interest changes and 1,650 MBoe associated with lower commodity prices and slightly higher lease operating expenses due to increased workover activity.

- *Extensions and discoveries:* During 2023, extensions and discoveries of 4,112 MBoe were attributable to additions of 1,520 MMBoe of proved developed reserves and 2,592 MMboe of proved undeveloped reserves in the Williston Basin.

Notable changes in proved reserves for the year ended December 31, 2022 included the following:

- *Acquisitions*. In 2022, total acquisitions of 3.2 MMBoe were primarily attributable to asset acquisitions of oil and gas properties (see Note 3).
- *Revisions to previous estimates.* In 2022, revisions to previous estimates increased proved reserves by a net amount of 0.2 MMBoe. Included in these revisions were 1.3 MMBoe of upward adjustments caused by higher crude oil and natural gas prices, 0.3 MMBoe of downward adjustments related to the removal of undeveloped drilling locations related to the SEC 5-year development rule, 0.3 MMBoe of downward adjustments related to changes in development plan, and 0.5 MMBoe of downward adjustments attributable to well performance when comparing the Company's reserve estimates at December 31, 2022 to December 31, 2021.
- *Extensions and discoveries*. In 2022, total extensions and discoveries of 1.8 MMBoe were attributable to additions of 1.6 MMBoe of proved developed reserves and 0.2 MMBoe of proved undeveloped reserves, respectively, in the Williston Basin.

Notable changes in proved reserves for the month ended December 31, 2021 included the following:

- *Revisions to previous estimates*. In the month ended December 31, 2021, revisions to previous estimates increased proved reserves by a net amount of 0.1 MMBoe that were primarily related to upward adjustments caused by higher crude oil and natural gas prices.

Notable changes in proved reserves for the year ended November 30, 2021 included the following:

- *Revisions to previous estimates*. In 2021, revisions to previous estimates increased proved developed and decreased proved undeveloped reserves by a net amount of 3.7 MMBoe. Included in these revisions were 4.3 MMBoe of upward adjustments caused by higher crude oil and natural gas prices and 6.9 MMBoe of downward adjustments related to the removal of undeveloped drilling locations due to a slower recovery of rig activity than expected in the Williston Basin, 0.5 MMBoe of downward adjustments related to the removal of drilled uncompleted wells in the Central Rockies related to the SEC 5-year development rule and 0.6 MMBoe of downward adjustments attributable to well performance when comparing the Company's reserve estimates at November 30, 2021 to November 30, 2020.
- *Extensions and discoveries*. In 2021, total extensions and discoveries of 1.3 MMBoe were attributable to additions of proved undeveloped locations in the Williston Basin.

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

The following table presents a standardized measure of discounted future net cash flows relating to proved crude oil and natural gas reserves, and the changes in standardized measure of discounted future net cash flows relating to proved crude oil and natural gas were prepared in accordance with the provisions of ASC 932 Extractive Activities— Oil and Gas. Future cash inflows were computed by applying average prices of crude oil and natural gas for the last 12 months to estimated future production. Future production and development costs were computed by estimating the expenditures to be incurred in developing and producing the proved crude oil and natural gas reserves at the end of the year (including asset retirement costs), based on year-end costs and assuming continuation of existing economic conditions. Future income tax expenses were calculated by applying appropriate year-end tax rates to future pretax cash flows relating to proved crude oil and natural gas reserves, less the tax basis of properties involved and tax credits and loss carry forwards relating to crude oil and natural gas producing activities. Income taxes for the Company are zero for the years ended December 31, 2022 and November 30, 2021 and the month ended December 31, 2021 due to the Predecessors's tax status as a pass-through entity. Future net cash flows are then discounted at the rate of 10%. Actual future cash inflows may vary considerably, and the standardized measure does not represent the fair value of the Company's crude oil and natural gas reserves.

(in thousands)	DECEMBER 31, 2023	2022	2021 (Transition Period)	NOVEMBER 30, 2021
Future Cash Inflows	$ 2,197,070	$ 3,420,665	$ 2,206,162	$ 2,151,098
Future Production Costs	(793,295)	(965,151)	(823,223)	(816,329)
Future Development Costs	(231,686)	(276,399)	(244,913)	(230,101)
Future Income Tax Expense	(175,276)	—	—	—
Future Net Cash Inflows	$ 996,813	$ 2,179,115	$ 1,138,026	$ 1,104,668
10% Annual Discount for Estimated Timing of Cash Flows	$ (421,122)	$ (999,131)	$ (509,625)	$ (503,055)
Standardized Measure of Discounted Future Net Cash Flows	$ 575,691	$ 1,179,984	$ 628,401	$ 601,613

The twelve-month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the Company's reserves. The price of other liquids is included in natural gas. The prices for the Company's reserve estimates were as follows:

	OIL $/Bbl	NATURAL GAS $/MMBtu
December 31, 2023	$ 78.21	$ 2.64
December 31, 2022	$ 94.14	$ 6.36
December 31, 2021	$ 66.55	$ 3.60
November 30, 2021	$ 64.81	$ 3.46

Changes in the Standardized Measure of Discounted Future Net Cash Flows at 10% per annum follow:

(in thousands)	DECEMBER 31, 2023	2022	2021 (Transition Period)	NOVEMBER 30, 2021
Beginning of Period	$ 1,179,984	$ 628,401	$ 601,613	$ 191,178
Sales of Oil and Natural Gas Produced, Net of Production Costs	(172,766)	(226,666)	(12,854)	(126,733)
Extensions and Discoveries	74,505	41,373	—	17,911
Previously Estimated Development Cost Incurred During the Period	30,411	714	—	16,924
Net Change of Prices and Production Costs	(473,479)	575,120	32,271	415,685
Change in Future Development Costs	(9,189)	(3,758)	(11,048)	22,606
Revisions of Quantity and Timing Estimates	(172,274)	18,140	2,153	(17,833)
Accretion of Discount	117,998	62,840	5,013	19,118
Change in Income Taxes	(106,380)	—	—	—
Purchases of Minerals in Place	90,929	122,421	117	23,272
Other	15,952	(38,601)	11,136	39,485
End of Period	$ 575,691	$ 1,179,984	$ 628,401	$ 601,613