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

FORM 10-K

☒ **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: 001-41537

GRANITE RIDGE RESOURCES, INC.

(*Exact Name of Registrant as Specified in Its Charter*)

Delaware	**1311**	**88-2227812**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

5217 McKinney Ave, Suite 400,
Dallas, TX 75205

(Address of principal executive offices)

(214) 396-2850

(Registrant's telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, par value $0.0001 per share	GRNT	New York Stock Exchange

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 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 Act). Yes ☐ No ☒

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2023, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $180,711,437 based on the $6.63 per share closing price of the registrant's common stock as reported on that day on the New York Stock Exchange.

As of March 5, 2024, there were 130,449,075 shares of the registrant's common stock outstanding.

Documents incorporated by reference: Portions of the definitive proxy statement related to the registrant's 2024 Annual Meeting of Stockholders to be filed pursuant to Regulation 14A are incorporated by reference into Part III of this Annual Report on Form 10-K.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

We are including the following discussion to inform our existing and potential security holders generally of some of the risks and uncertainties that can affect our company and to take advantage of the “safe harbor” protection for forward-looking statements that applicable federal securities law afford.

From time to time, our management or persons acting on our behalf may make forward-looking statements to inform existing and potential security holders about our company. All statements other than statements of historical facts included in this Annual Report on Form 10-K (this "Annual Report"), including, without limitation, statements regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, indebtedness covenant compliance, capital expenditures, production, cash flow, borrowing base under our Credit Agreement (as defined below), our intention or ability to pay or increase dividends on our capital stock, and impairment are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as “estimate,” “project,” “predict,” “believe,” “expect,” “continue,” “anticipate,” “target,” “could,” “plan,” “intend,” “seek,” “goal,” “will,” “should,” “may” or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future production, sales, market size, collaborations, cash flows, and trends or operating results also constitute such forward-looking statements.

Forward-looking statements involve inherent risks and uncertainties, and important factors (many of which are beyond our company’s control) that could cause actual results to differ materially from those set forth in the forward-looking statements, including the following:

- changes in current or future commodity prices and interest rates;
- supply chain disruptions;
- infrastructure constraints and related factors affecting our properties;
- our ability to acquire additional development opportunities and potential or pending acquisition transactions, as well as the effects of such acquisitions on our company’s cash position and levels of indebtedness;
- changes in our reserves estimates or the value thereof;
- operational risks including, but not limited to, the pace of drilling and completions activity on our properties;
- changes in the markets in which Granite Ridge competes;
- geopolitical risk and changes in applicable laws, legislation, or regulations, including those relating to environmental matters;
- cyber-related risks;
- the fact that reserve estimates depend on many assumptions that may turn out to be inaccurate and that any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves;
- the outcome of any known and unknown litigation and regulatory proceedings;
- limited liquidity and trading of Granite Ridge’s securities;
- acts of war, terrorism or uncertainty regarding the effects and duration of global hostilities, including the Israel-Hamas conflict, the Russia-Ukraine war, continued instability in the Middle East, including from the Houthi rebels in Yemen, and any associated armed conflicts or related sanctions which may disrupt commodity prices and create instability in the financial markets;
- market conditions and global, regulatory, technical, and economic factors beyond Granite Ridge’s control, including the potential adverse effects of world health events, such as the COVID-19 pandemic, affecting capital markets, general economic conditions, global supply chains and Granite Ridge’s business and operations;

- increasing regulatory and investor emphasis on, and attention to, environmental, social, and governance matters;
- our ability to establish and maintain effective internal control over financial reporting, including our ability to remediate the existing material weaknesses in our internal controls; and
- other factors discussed in this Annual Report under the section titled Item 1A. “Risk Factors,” as updated by any subsequent Quarterly Reports on Form 10-Q, which we file with the United States Securities and Exchange Commission (“SEC”).

We have based any forward-looking statements on our current expectations and assumptions about future events. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties, most of which are difficult to predict and many of which are beyond our control. Accordingly, results actually achieved may differ materially from expected results described in these statements. Forward-looking statements speak only as of the date they are made. You should carefully consider the statements in the section titled Item 1A. "Risk Factors” and other sections of this report, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements. Our company does not undertake, and specifically disclaims, any obligation to update any forward-looking statements to reflect events or circumstances occurring after the date of such statements.

Reserve engineering is a process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data, and the price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities, or changes in commodity prices, may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas and oil that are ultimately recovered.

Readers are urged not to place undue reliance on these forward-looking statements, which speak only as of the date of this Annual Report. We assume no obligation to update any forward-looking statements in order to reflect any event or circumstance that may arise after the date of this report, other than as may be required by applicable law or regulation. Readers are urged to carefully review and consider the various disclosures made by us in our reports filed with the SEC which attempt to advise interested parties of the risks and factors that may affect our business, financial condition, results of operation and cash flows. If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, our actual results may vary materially from those expected or projected.

GLOSSARY OF TERMS

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

Terms used to describe quantities of crude oil and natural gas:

"*Bbl*." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

"*Boe*." A barrel of oil equivalent and is a standard convention used to express crude oil, NGL and natural gas volumes on a comparable crude oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of crude oil or NGL.

"*Btu or British Thermal Unit*." The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

"*MBbl*." One thousand barrels of crude oil, condensate or NGLs.

"*MBoe*." One thousand Boe.

"*Mcf* ." One thousand cubic feet of natural gas.

"*MMBtu*." One million British Thermal Units.

"*MMcf*." One million cubic feet of natural gas.

"*NGLs*." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

Terms used to describe our interests in wells and acreage:

"*Basin*" A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"*Completion*" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs, and/or natural gas.

"*Developed acreage*" Acreage consisting of leased acres spaced or assignable to productive wells. Acreage included in spacing units of infill wells is classified as developed acreage at the time production commences from the initial well in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Development costs*" Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. For a complete definition of development costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(7).

"*Development well*" A well drilled within the proved area of a crude oil, NGL, or natural gas reservoir to the depth of a stratigraphic horizon (rock layer or formation) known to be productive for the purpose of extracting proved crude oil, NGL, or natural gas reserves.

"*Differential*" The difference between a benchmark price of crude oil and natural gas, such as the NYMEX crude oil spot market price, and the wellhead price received.

"*Dry hole*" A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

"*Field*" An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"*Formation*" A layer of rock which has distinct characteristics that differs from nearby rock.

"*Gross acres or Gross wells*" The total acres or wells, as the case may be, in which a working interest is owned.

"*Held by operations*" A provision in an oil and gas lease that extends the stated term of the lease as long as drilling operations are ongoing on the property.

"*Held by production*" A provision in an oil and gas lease that extends the stated term of the lease as long as the property produces a minimum quantity of crude oil, NGLs, and natural gas.

"*Hydraulic fracturing*" The technique of improving a well's production by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

"*Horizontal drilling*" A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"*Infill well*" A subsequent well drilled in an established spacing unit of an already established productive well in the spacing unit. Acreage on which infill wells are drilled is considered developed commencing with the initial productive well established in the spacing unit. As such, the addition of an infill well does not have any impact on a company's amount of developed acreage.

"*Lease operating expenses*" The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, marketing and transportation costs, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

"*Net acres*" The percentage ownership of gross acres. Net acres are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 10% working interest in a lease covering 640 gross acres is equivalent to 64 net acres).

"*Net well*" The total of fractional working interests owned in gross wells.

"*NYMEX*" The New York Mercantile Exchange.

"*OPEC*" The Organization of Petroleum Exporting Countries.

"*Operator*" The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

"*Production costs*" Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).

"*Productive well*" A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"*Recompletion*" The process of treating a drilled well followed by the installation of permanent equipment for the production of crude oil, NGLs or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"*Reservoir*" A porous and permeable underground formation containing a natural accumulation of producible crude oil, NGLs and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

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

"*Spacing*" The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"*Spot market price*" The cash market price without reduction for expected quality, transportation and demand adjustments.

"*Undeveloped acreage*" Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage includes net acres held by operations until a productive well is established in the spacing unit.

"*Unit*" The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"*Wellbore*" The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"*West Texas Intermediate or WTI*" A light, sweet blend of oil produced from the fields in West Texas.

"*Working interest*" The right granted to the lessee of a property to explore for and to produce and own crude oil, NGLs, natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"*Workover*" Operations on a producing well to restore or increase production.

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

"*Possible reserves*" The additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

"*Pre-tax PV-10% or PV-10*" The estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

"*Probable reserves*" 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.

"*Proved developed producing reserves (PDPs)*" Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

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

"*Proved reserves*" The quantities of crude oil, NGLs and natural gas, which, by analysis of geosciences 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.

"*Proved undeveloped reserves*" or "*PUDs*" 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. Proved reserves for other undrilled units are claimed only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves will not 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 tests in the area and in the same reservoir or an analogous reservoir.

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

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

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

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

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions.

"*Reserves*" Reserves are 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.

"Standardized measure" Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period 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 inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

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Summary of Risk Factors

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

Risks Related to Granite Ridge's Business and Operations

- As a non-operator, Granite Ridge's development of successful operations relies extensively on third parties.
- The loss of a key member of the Manager's management team could diminish our ability to conduct our operations and harm our ability to execute our business plan.
- Oil and natural gas prices are volatile. Extended declines in such prices have adversely affected, and could in the future adversely affect, Granite Ridge's business and results of operations.
- Certain of Granite Ridge's undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established, operations are commenced or the leases are extended.
- Granite Ridge's estimated reserves are based on many assumptions that may prove to be inaccurate.
- Granite Ridge's future success depends on its ability to replace reserves that its operators produce.
- Deficiencies of title to Granite Ridge's leased interests could significantly affect its financial condition.
- Various laws and regulations govern aspects of the oil and gas business including natural resource conservation and environmental, health, and safety matters, and these laws and regulations could change and become stricter over time.
- Fuel and energy conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry could reduce demand for oil and natural gas.
- Increased attention to environmental, social and governance matters may impact Granite Ridge's business.
- Granite Ridge relies on the Manager for various certain key services under the MSA, which could result in conflicts of interest and other unforeseen risks.
- Certain of our unaudited financial statements for the three and nine months ended September 30, 2022 were required to be restated and our management identified material weaknesses in our internal control over financial reporting. Management implemented steps that remediated these material weaknesses effective as of December 31, 2023. These steps may, however, not be sufficient to prevent a future weakness. A material weakness may result in a misstatement of accounts or disclosures that would result in a material misstatement of the Company's financial statements that would not be prevented or detected on a timely basis or cause us to fail to meet our obligations under securities laws, stock exchange listing rules, or debt instrument covenants to file periodic financial reports on a timely basis.
- The relative lack of public company experience by Granite Ridge's management team may put Granite Ridge at a competitive disadvantage.
- The borrowing base under our Credit Agreement may be reduced in light of commodity price declines, which could limit us in the future.

Risks Related to Ownership of Granite Ridge Common Stock

- Sales by our securityholders or issuances by the Company, or the perception that such sales or issuances may occur may cause the market price of Granite Ridge common stock to drop.
- Granite Ridge qualifies as an "emerging growth company", which could make its securities less attractive.
- Anti-takeover provisions in the Granite Ridge organizational documents could delay or prevent a change of control.
- Granite Ridge is a "controlled company" under the corporate governance rules of the NYSE, which means that our stockholders are not afforded the same protections as stockholders of companies that are not "controlled companies."
- Changes in applicable tax laws or interpretations thereof or the imposition of new or increased taxes or fees may increase our future tax liabilities and adversely affect our operating results and cash flows.

We describe these and other risks in much greater detail below in the section titled Item 1A. "Risk Factors."

GRANITE RIDGE RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K
FOR FISCAL YEAR ENDED DECEMBER 31, 2023

PART I

Item 1. *Business*

In this "Business" section, unless otherwise specified or the context otherwise requires, "Granite Ridge," the "Company," "we," "us," and "our" refer to Granite Ridge Resources, Inc. and its consolidated subsidiaries. The following discussion of our business should be read in conjunction with the accompanying audited consolidated financial statements and related notes included elsewhere in this Annual Report.

Overview

Granite Ridge is a scaled, non-operated oil and gas exploration and production company. We own a portfolio of wells and top-tier acreage across the Permian and four other prolific unconventional basins across the United States. Rather than drill wells ourselves, we increase asset diversity and decrease overhead by investing in a smaller piece of a larger number of high-graded wells drilled by proven public and private operators. As a non-operating partner, we pay our pro rata share of expenses, but we are not burdened by long-term contracts and drilling obligations common to operators.

We drive capital appreciation by reinvesting cash flow generated from our oil and gas wells to:

- participate in the development of new wells alongside operators with significant experience in developing and producing hydrocarbons in our core asset areas;
- acquire additional rights to participate in future wells; and
- leverage our scalable, tech-enabled platform to consolidate non-operated assets.

Business Combination

Granite Ridge is a Delaware corporation, formed on May 9, 2022 to consummate the Business Combination (as defined below). On October 24, 2022 (the "Closing Date"), Granite Ridge and Executive Network Partnering Corporation, a Delaware corporation ("ENPC") consummated a business combination pursuant to the terms of the Business Combination Agreement, dated as of May 16, 2022 (the "Business Combination Agreement"), by and among ENPC, Granite Ridge, ENPC Merger Sub, Inc., a Delaware corporation and a wholly-owned subsidiary of Granite Ridge ("ENPC Merger Sub"), GREP Merger Sub, LLC, a Delaware limited liability company and a wholly-owned subsidiary of Granite Ridge ("GREP Merger Sub"), and GREP Holdings, LLC, a Delaware limited liability company ("GREP").

Pursuant to the Business Combination Agreement, on the Closing Date, (i) ENPC Merger Sub merged with and into ENPC (the "ENPC Merger"), with ENPC surviving the ENPC Merger as a wholly-owned subsidiary of Granite Ridge and (ii) GREP Merger Sub merged with and into GREP (the "GREP Merger," and together with the ENPC Merger, the "Mergers"), with GREP surviving the GREP Merger as a wholly-owned subsidiary of Granite Ridge (the transactions contemplated by the foregoing clauses (i) and (ii) the "Business Combination," and together with the other transactions contemplated by the Business Combination Agreement, the "Transactions"). Immediately prior to the Transactions, the net assets of certain funds managed by Grey Rock Energy Management, LLC ("Grey Rock") were contributed to GREP and are now held by the Company.

Assets of Granite Ridge

We hold interests in wells in core operating areas of the Permian, Eagle Ford, Bakken, Haynesville and Denver-Julesburg ("DJ") plays (collectively, our "Properties"). Non-operated working interests constitute the central part of our investment strategy. However, we have also made certain investments in minerals, and certain other oil and natural gas assets that are incidental or ancillary to preserve, protect, or enhance our assets, or are acquired as part of a package with the non-operated working interests. The operators of our Properties include public exploration and production companies and experienced private companies.

The following is a summary of information regarding our assets as of December 31, 2023, including reserves information as estimated by our third-party independent reserve engineers, Netherland, Sewell & Associates, Inc.

	As of December 31, 2023								
		Productive Oil Wells		Productive Gas Wells					
	Net Acres	Gross	Net	Gross	Net	Average Daily Production (Boe per day)	Proved Reserves (MBoe)	% Oil	% Proved Developed
Permian	9,593	575	46.30	1	—	11,453	32,300	56%	42%
Eagle Ford	6,809	120	24.80	93	6.90	2,843	7,874	55%	64%
Bakken	13,487	938	39.00	—	—	2,326	4,500	73%	96%
Haynesville	5,502	—	—	117	16.40	5,595	4,834	0%	89%
DJ	2,086	967	42.20	15	0.90	2,094	3,963	34%	98%
Total	37,477	2,600	152.30	226	24.20	24,311	53,472	51%	58%

Business Strategy

We are focused on creating long-term stockholder value by recycling cash flow into accretive growth opportunities while paying a quarterly cash dividend and maintaining a healthy balance sheet. Key elements of our strategy include:

Build a Diversified Portfolio: Our non-operated strategy of investing in a smaller piece of a larger number of high-graded wells allows us to build a portfolio of upstream oil and gas assets across the United States that is highly diversified in terms of geography, geology, hydrocarbon mix, and operator (both public and private).

Maintain a Healthy Balance Sheet: Prudent balance sheet management is a core tenet of both our risk management and value-creation strategies. In a challenging commodity price environment, our goal is to maintain liquidity to capitalize on accretive opportunities and to stay comfortably within credit covenants across commodity price cycles.

Pay a Quarterly Dividend: We believe that a quarterly cash dividend is the cornerstone of a sustainable and resilient business model. We expect that Granite Ridge will initially pay quarterly cash dividends of $0.11 (or $0.44 per fiscal year).

Be a Good Partner: As a non-operator, we lean heavily on our operating partners. By building relationships across multiple disciplines and actively seeking creative opportunities to be a value-added partner, we can often access more and more timely data as well as mitigate some of the challenges inherent in non-op around development plans and timing.

Empower People: Our people are the lifeblood of our organization. We, and Grey Rock Administration, LLC (the "Manager") which supplies land, accounting, engineering, finance, and other back-office services to us in connection with continued management of the Properties contributed to us as part of the Business Combination, employ a case-based recruiting process to identify talent that has both the ability and desire to have a positive impact on an organization but may have been restricted by the bureaucracy of larger companies. We then encourage, support, and incentivize our team to develop and implement ideas that make us better.

Leverage Data: As an owner in over 3,100 gross wells under 66 operators across 7 states and 35 counties/parishes, we have an immense amount of data. We continually invest both human and financial capital to further develop our proprietary information systems to help us make better investment decisions faster.

Source Deals Directly: While we evaluate marketed assets, we typically find higher risk-adjusted returns from aggregating multiple smaller transactions as opposed to buying larger marketed packages. As such, we seek to capture opportunities at an attractive entry cost by targeting non-marketed packages and developing creative partnerships.

Capture Accretive Opportunities with Upside: We focus on investments with high-graded drilling inventory rather than simply buying production. While development offers a wider range of outcomes, we mitigate risk by partnering with experienced operators in proven areas and believe drilling offers superior risk-adjusted returns.

Mitigate Price Risk: While we cannot remove commodity price risk, we seek opportunities to reduce volatility. In addition to entering into hedging derivative instruments tied to the price of oil or natural gas, we actively pursue diversification across hydrocarbon, basin, and operator to mitigate price swings specific to any particular area, company or contract.

Adapt: Be it from technology, macro events, political dynamics or investor sentiment, change is the only constant in the oil and gas industry. With a diversified asset base and limited long-term contracts or drilling obligations (we elect to participate in drilling on a well-by-well basis), our business is built to maximize adaptability.

Commit to Environmental Stewardship: As a non-operator, it is critical that we partner with operators that are proven and responsible environmental stewards. In additional to the moral and ethical drivers, it is a prudent business decision because if an operator with poor ESG standards loses the social license to operate, we may end up with stranded inventory.

Operating Areas

Permian

The Permian Basin extends from southeastern New Mexico into west Texas and is currently one of the most active drilling regions in the United States. The Permian Basin consists of mature legacy onshore oil and liquids-rich natural gas reservoirs. The extensive operating history, favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, horizontal development potential and liquids-rich reserves make the Permian Basin one of the most prolific oil-producing regions in the United States. At December 31, 2023, 60% of our total proved reserves were located in the Permian Basin. During the year ended December 31, 2023, operators completed 123 gross (13.26 net) wells in the Permian Basin.

Eagle Ford

The Eagle Ford shale formation stretches across south Texas and includes Austin Chalk and Buda formations. At December 31, 2023, 15% of our total proved reserves were located in the Eagle Ford Basin. During the year ended December 31, 2023, operators completed 24 gross (5.84 net) wells in the Eagle Ford Basin.

Bakken

The Williston Basin stretches through North Dakota, the northwest part of South Dakota, and eastern Montana and is best known for the Bakken/Three Forks shale formations. The Bakken ranks as one of the largest oil developments in the United States. At December 31, 2023, 8% of our total proved reserves were located in the Bakken Basin. During the year ended December 31, 2023, operators completed 34 gross (1.47 net) wells in the Bakken Basin.

Haynesville

The Haynesville Basin is a premier natural gas basin located in Northwestern Louisiana and East Texas. At December 31, 2023, 9% of our total proved reserves were located in the Haynesville Basin. During the year ended December 31, 2023, operators completed 9 gross (1.13 net) wells in the Haynesville Basin.

DJ

The Denver-Julesburg Basin, also known as the DJ basin, is a geologic basin centered in eastern Colorado stretching into southeast Wyoming, western Nebraska and western Kansas. Development in this area is currently focused on horizontal drilling in the Niobrara and Codell formations. At December 31, 2023, 7% of our total proved reserves were located in the DJ Basin. During the year ended December 31, 2023, operators completed 124 gross (2.85 net) wells in the DJ Basin.

Industry Operating Environment

The oil and natural gas industry is a global market impacted by many factors, including government regulations, particularly in the areas of taxation, energy, climate change and the environment, political and social developments in the Middle East and Russia, demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas as it is a primary heating source.

Oil and natural gas prices have been volatile and may continue to be volatile in the future. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or natural gas prices may affect planned capital expenditures and the oil and natural gas reserves that the Properties can economically produce. If commodity prices decline, the cost of developing, completing, and operating a well may not decline in proportion to prices received for the production, resulting in higher operating and capital costs as a percentage of revenues.

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 acreage. In addition, we acquire wellbore-only working interests in wells separate from the underlying leasehold interests from third parties unable or unwilling to participate in particular well proposals. We typically depend on drilling partners to propose, permit, and initiate the drilling of wells. Prior to commencing drilling, our operating partners are required to provide all owners of oil, natural gas, and mineral interests within the designated spacing unit the opportunity to participate in the drilling costs and revenues of the well proportionate to their pro-rata share of such interest within the spacing unit. We assess each participation opportunity in any given well on a case-by-case basis and expect to meet our return thresholds based upon our estimates of ultimate recoverable oil and natural gas from such well, forward curve pricing, expected oil and gas prices, expertise of the operator in such well, and completed well costs from each project, as well as other factors.

Historically, we have participated, pursuant to our working interests, in a vast majority of the wells proposed to us. However, declines in oil and natural gas 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 and engineering team uses an extensive proprietary data set to assist us in making these economic decisions. Given our acreage footprint and substantial number of well participations, we believe we can make relatively accurate decisions regarding the economics of well participation.

While we regularly have the right to take a portion of our production in kind, we typically elect to have our operating partners market and sell oil and natural gas produced from wells in which we have an interest. Our operating partners coordinate the transportation of our oil and natural gas production from their wells to appropriate pipelines or rail transport facilities pursuant to arrangements that they negotiate and maintain with various parties purchasing the production. We may, from time to time, enter into financial hedging contracts to help mitigate pricing risk and volatility with respect to differentials.

Competition

Although we focus on a target asset class and deal size where we believe competition and costs are reduced as compared to the broader oil and natural gas industry, the overall industry remains intensely competitive. We compete with other oil and natural gas exploration and production companies, some of which have substantially greater resources and may be able to pay more for exploratory prospects and productive oil and natural gas properties, and competition for our target asset classes is subject to increase in the future. Our larger or integrated competitors may be better able to absorb the burden of existing, as well as any changes to, federal, state, and local laws and regulations, which would adversely affect our competitive position. Our ability to acquire additional properties in the future is dependent upon our ability and resources to evaluate and select suitable properties and to consummate transactions in this highly competitive environment.

Marketing and Customers

The market for oil and natural gas produced from our Properties depends on many factors, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of pipelines and other transportation and storage facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial, and individual consumers.

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We rely on our operating partners to market and sell our production. Our operating partners include a variety of exploration and production companies, from large publicly traded companies to privately-owned companies.

The following table sets forth the percentage of revenues attributable to third-party operating partners who have accounted for 10% or more of revenues attributable to our assets during the years ended December 31, 2023, 2022 and 2021.

Major Operators	2023	2022	2021
Operator A	11 %	12 %	12 %
Operator B	*	*	15 %
Operator C	12 %	10 %	*
Operator D	*	10 %	*

* Less than 10%

No other operator accounted for 10% or more of revenue attributable to our assets on a combined basis in the years ended December 31, 2023, 2022, or 2021. The loss of any such operator could adversely affect revenues attributable to the Company's assets in the short term.

Title to Properties

Our oil and natural gas properties are subject to customary royalty and other interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes, and other burdens, including other mineral encumbrances and restrictions. At the closing of the Business Combination, we entered into a credit agreement with Texas Capital Bank, as administrative agent, and the lenders named therein (as amended, the "Credit Agreement"), secured by a first priority mortgage and security interest in substantially all of our and our restricted subsidiaries' assets.

We believe that we have satisfactory title to, or rights in, the Properties. As is customary in the oil and natural gas industry, due diligence investigation of title is made at the time of acquisition of any properties.

Seasonality

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

Principal Agreements Affecting Our Business

We generally do not own physical real estate but, instead, our assets are primarily comprised of leasehold interests subject to the terms and provisions of lease agreements that provide us with the right to participate in drilling and maintenance of wells in specific geographic areas. Lease arrangements that comprise our acreage positions are generally established using industry-standard terms that have been established and used in the oil and natural gas industry for many years. Many of our leases are or were acquired from other parties that obtained the original leasehold interest prior to our acquisition of the leasehold interest.

In general, our lease agreements stipulate three-year primary terms. Bonuses and royalty rates are negotiated on a case-by-case basis consistent with industry standard pricing. Once a well is drilled and production is established, the leased acreage in the applicable spacing unit is considered developed acreage and is held by production or continuous drilling obligations. Other locations within the drilling unit created for a well may also be drilled at any time with no time limit as long as the lease is held by production and continuous drilling obligations are satisfied. Given the current pace of drilling in the areas of our operations, we do not believe lease expiration issues will materially affect our acreage position.

At the closing of the Business Combination, we entered into a Management Services Agreement ("MSA") with the Manager, pursuant to which the Manager supplies land, accounting, engineering, finance, and other back-office services to us in connection with continued management of the Properties contributed to us as part of the Business Combination.

Governmental Regulation and Environmental Matters

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

Regulation of Oil and Natural Gas Production

Our oil and natural gas exploration and production business and development and operation of the Properties are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, North Dakota, Montana, Louisiana, Colorado, Oklahoma, New Mexico, and Texas require permits for drilling operations, drilling bonds or other forms of financial security, and reports concerning operations, and impose other requirements relating to the exploration 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, 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 production, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. Moreover, the current administration has indicated that it expects to impose additional federal regulations limiting access to and production from federal lands. The effect of these regulations is to limit the amount of oil and natural gas that can be produced from the wells in which we participate and to limit the number of wells or the locations at which our operating partners can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas, and natural gas liquids within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties or other liabilities. 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, and typically become more stringent over time, we are unable to predict the future cost or impact of our and our operating partners' compliance 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 profitability. Additionally, unforeseen environmental incidents may occur on the Properties or past non-compliance with environmental laws or regulations may be discovered, resulting in unforeseen liabilities. Additional proposals, proceedings, and regulations that affect the oil and natural gas industry are regularly considered by Congress; the courts; federal regulatory agencies such as the Federal Energy Regulatory Commission ("FERC"), the U.S. Environmental Protection Agency, and the Bureau of Land Management; and state legislatures and regulatory authorities. We cannot predict when or whether any such proposals may become effective, the substance of those regulations, or the outcome of such proceedings. Therefore, we are unable to predict with certainty the future compliance costs or implications of compliance on profitability.

Regulation of Transportation of Oil

Sales of crude oil, condensate, and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Sales of crude oil are affected by the availability, terms, and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted, and market-based rates may be permitted in certain circumstances.

Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. On January 20, 2022, the 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 operations on the Properties 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. In Texas, when oil or natural gas pipelines operate at full capacity, access is generally governed by pro-rationing rules established by the Railroad Commission of Texas (“RRC”), in addition to certain pro-rationing provisions that may be set forth in the pipelines’ published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to our operating partners to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

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

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

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which our operating partners 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 is produced from wells in which we hold an interest, as well as the revenues we receive from sales of natural gas.

Environmental Matters

A variety of stringent federal, tribal, state, and local laws and regulations govern the environmental aspects of the oil and gas business. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may: (i) require the acquisition of a permit or other authorization and procurement of financial assurance before construction or drilling commences and for certain other activities; (ii) limit or prohibit construction, drilling or other activities on certain lands lying within wilderness and other protected areas; and (iii) impose substantial liabilities for pollution resulting from our operations. Any noncompliance with these laws and regulations could subject us or any of our properties to material administrative, civil, or criminal penalties; investigatory or remedial obligations; injunctive relief; or other liabilities. Additionally, compliance with these laws and regulations may, from time to time, result in increased costs of operations, delay in operations, or decreased production, and may affect acquisition costs.

The permits required for development and construction of and operations on the Properties may be subject to revocation, modification, and renewal by issuing authorities, and such permitting could cause delays in development, construction, or operation of the Properties, thus increasing costs and potentially affecting our profitability. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of our management, the operators of the Properties are in substantial compliance with current applicable environmental laws and regulations, and we have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on us or any of our properties or operating partners, as well as the oil and natural gas industry in general.

The federal Clean Air Act (“CAA”) and comparable state laws and regulations impose obligations related to the emission of air pollutants, including emissions from oil and gas sources. Under the CAA and comparable state laws, the Environmental Protection Agency (“EPA”) and state environmental regulatory agencies have developed stringent regulations governing both permitting of emissions and emissions of certain air pollutants at specified sources, including certain oil and gas sources. Both existing CAA and state regulations, and any future regulations, may require pre-approval for the construction, expansion, or modification of certain facilities that produce, or which are expected to produce, air emissions. Such regulations may also impose stringent air permit requirements, limit natural gas venting and flaring activity, and require the use of specific equipment or technologies to control emissions. Under the CAA, the EPA has enacted final regulations requiring owners and operators of certain facilities that emit greenhouse gases above certain thresholds to report those emissions. The EPA has also promulgated regulations establishing construction and operating permit requirements for greenhouse gas emissions from stationary sources that already emit conventional pollutants (i.e., sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone, and lead) above certain thresholds. Further, the CAA requires that owners and operators of stationary sources producing, processing, and storing extremely hazardous substances have a general duty to identify hazards associated with an accidental release, design and maintain a safe facility, and minimize the consequences of any releases that occur. The CAA further requires such facilities that handle more than threshold amounts of extremely hazardous substances to develop risk management plans intended to prevent and minimize impacts if releases do occur.

CAA regulations also include New Source Performance Standards (“NSPS”) for the oil and natural gas source category to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production, storage, transportation, and processing activities. These rules currently require all oil or natural gas wells that have been hydraulically fractured or refractured since November 30, 2016 to be completed using so-called “green completion” technology, which significantly reduces VOC emissions, and has the co-benefit of also limiting methane, a greenhouse gas. These regulations, referred to as NSPS Subpart OOOO and OOOOa, also apply to storage tanks and other equipment in the affected oil and natural gas industry segments, and, commencing with Subpart OOOOa, were designed to also limit methane from new and modified sources in the oil and gas sector. The EPA has since modified and rolled back various aspects of the rules, including removal of the transmission and storage sectors of the oil and gas industry from regulation and of the methane-specific standards for the production and processing segments of the industry. Subsequently, Congress partially overturned that rollback in June 2021. In December 2023, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc. Under the final rules, states have two years to prepare and submit their plants to impose methane emission controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources and include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. It is likely, however, that the final rule and its requirements will be subject to legal challenges. The requirements of the EPA's final methane rules have the potential to increase the operating costs of our operators and thus may adversely affect our financial results and cash flows. Moreover, failure to comply with these CAA requirements can result in the imposition of substantial fines and penalties as well as costly injunctive relief.

The federal Clean Water Act (“CWA”) and comparable state laws and regulations impose strict obligations related to discharges of pollutants and dredge and fill material into regulated bodies of water, including wetlands. The discharge of pollutants into regulated waters is prohibited except in accordance with a permit issued by the EPA, the United States Army Corps of Engineers (“USACE”), or state agency or tribe with a delegated CWA permit program. Permitting of discharges of stormwater associated with oil and gas facility construction or operation activities may also be required. Compliance with permitting requirements could increase the length of time it takes to construct an oil and gas facility, and impose heightened operating standards, which in turn could increase our operators' cost of construction and operation. In addition, compliance with CWA requirements could limit the locations where wells, other oil and natural gas facilities, and associated access resources can be constructed.

The scope of regulated waters has been subject to substantial controversy. In 2015 and 2020, respectively, the Obama and Trump Administrations each published final rules attempting to define the federal jurisdictional reach over waters of the United States (“WOTUS”). However, both of these rulemakings were subject to legal challenge. In January 2023, the EPA and Corps published a final rule based on the pre-2015 definition, with updates to incorporate existing Supreme Court decisions and regulatory guidance. However, the January 2023 rule was challenged and is currently enjoined in 27 states. 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 January 2023 rule and significantly narrowed its scope, resulting in a revised rule being issued in September 2023. However, due to the injunction on the January 2023 rule, the implementation of the September 2023 rule currently varies by state. In the 27 states subject to the injunction, the agencies are interpreting the definition of WOTUS consistent with the pre-2015 regulatory regime and the changes made by the Sackett decision, which utilizes the "continuous surface connection" test to determine if wetlands qualify as WOTUS. In the remaining 23 states, the agencies are implementing the September 2023 rule, which did not define the term "continuous surface connection." Therefore, some uncertainty remains as to how broadly the September 2023 rule and the Sackett decision will be interpreted by the agencies. To the extent the implementation of the final rule, results of the litigation, or any action further expands the scope of the CWA's jurisdiction, operators could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the federal CWA, imposes duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills into or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities that store oil in more than threshold quantities, the release of which could reasonably be expected to reach jurisdictional waters, must develop, implement, and maintain Spill Prevention, Control, and Countermeasure ("SPCC") Plans.

The federal Safe Drinking Water Act ("SDWA"), its implementing regulations, and delegated regulatory programs (*e.g.*, state programs) impose requirements on drilling and operation of underground injection wells, including injection wells used for the injection disposal of oil and gas wastes, such as produced water. In addition, the EPA has asserted authority under the SDWA to regulate hydraulic fracturing that uses diesel fuel. The EPA directly administers the Underground Injection Control ("UIC") program in some states, and in others, administration of all or portions of the program is delegated to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure that the disposed waters are not leaking into groundwater. In addition, because some states, including Oklahoma and Texas, have become concerned that the injection or disposal of produced water could, under certain circumstances, trigger or contribute to earthquakes, they have issued directives to operators and/or have adopted or are considering additional regulations regarding such disposal methods. Changes in regulations or the inability to obtain permits for new disposal wells in the future may affect the ability of the operators of the Properties to dispose of produced water and ultimately increase the cost of operation of the Properties or delay production schedules. For example, in 2014, the RRC published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant for a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the RRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. Furthermore, in response to a number of earthquakes in recent years in the Midland Basin, in September 2021 the RRC announced that it will not issue any new saltwater disposal ("SWD") well permits in an area known as the Gardendale Seismic Response Area ("SRA"), and will require existing SWD wells in that area to reduce their maximum daily injection rate to 10,000 barrels per day per well. In December 2021, the RRC went on to suspend all well activity in deep formations in the Gardendale SRA, effectively terminating 33 disposal well permits. And in October 2021 and January 2022, respectively, the RRC identified two additional SRAs: the Northern Culberson-Reeves SRA and the Stanton SRA. Operators in the Northern Culberson-Reeves and Stanton SRAs have implemented seismic response plans, which include expanded data collection efforts, contingency responses for future seismicity, and scheduled checkpoint updates with RRC staff. In December 2023, the RRC suspended the permits of 23 deep disposal wells in the Northern Culberson-Reeves SRA.

In addition, several cases have in recent years put a spotlight on the issue of whether injection wells may be regulated under the CWA if a direct hydrological connection to a jurisdictional surface water can be established. The EPA has also brought attention to the reach of the CWA's jurisdiction in such instances by issuing a request for comment in February 2018 regarding the applicability of the CWA permitting program to discharges into groundwater with a direct hydrological connection to jurisdictional surface water, which hydrological connections should be considered "direct," and whether such discharges would be better addressed through other federal or state programs. In a statement issued by EPA in April 2019, the Agency concluded that the CWA should not be interpreted to require permits for discharges of pollutants that reach surface waters via groundwater. However, in April 2020, the Supreme Court issued a ruling in *County of Maui, Hawaii v. Hawaii Wildlife Fund*, holding that discharges into groundwater may be regulated under the CWA if the discharge is the "functional equivalent" of a direct discharge into navigable waters. On January 14, 2021, the EPA issued a guidance on the ruling, which emphasized that discharges to groundwater are not necessarily the "functional equivalent" of a direct discharge based solely on proximity to jurisdictional waters. However, on September 16, 2021, the EPA rescinded its January 14, 2021 guidance. If in the future CWA permitting is required for saltwater injection wells as a result of the

Supreme Court's ruling in *County of Maui, Hawaii v. Hawaii Wildlife Fund*, the costs of permitting and compliance for injection well operations by the companies that operate the Properties could increase.

The federal Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state statutes impose strict liability, and in some cases joint and several liability, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or previous owner and operator of a site where a hazardous substance has been disposed and persons who generated, transported, disposed or arranged for the transport or disposal of a hazardous substance. Such persons may be responsible for the costs of investigating releases of hazardous substances, remediating releases of hazardous substances, and compensating for damages to natural resources. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to public health or the environment and to seek recovery from such responsible classes of persons of the costs of such an action, including the costs of certain health studies. From time to time, the EPA may designate additional materials as hazardous substances under CERCLA, which could result in additional investigation and remediation at current Superfund sites, or the reopening of Superfund sites that previously received regulatory closure. For example, on August 26, 2022, EPA announced a proposal to designate as hazardous substances perfluorooctanoic acid ("PFOA") and perfluorooctanesulfonic acid ("PFOS"), which have been commonly used in a variety of industrial and consumer products. EPA is expected to finalize that proposal in 2024. While CERCLA does contain an exclusion for petroleum, the exclusion is limited and could ultimately be repealed, and oil and gas facilities often contain hazardous substances subject to regulation under CERCLA. Although the non-operating status of our interests in the Properties likely presents a lower risk that we would be held subject to CERCLA liability, should we or any of our operating partners become subject to strict liability under federal or state laws for environmental damages caused by previous owners or operators of properties we purchase, without regard to fault, our profitability could be negatively affected.

The federal Resource Conservation and Recovery Act ("RCRA") and comparable state laws regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. Most wastes associated with the exploration, development, and production of oil or gas, including drilling fluids and produced water, are currently regulated as non-hazardous wastes pursuant to an exemption from regulation as a hazardous waste under RCRA. However, certain wastes generated at oil and gas exploration, development, production, and transmission sites are regulated as hazardous under RCRA. It is also possible that "RCRA-exempt" exploration and production wastes currently regulated as non- hazardous could be regulated as hazardous wastes in the future.

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds and their habitat, and natural resources. These statutes include the federal Endangered Species Act, the Migratory Bird Treaty Act ("MTBA"), the Bald and Golden Eagle Protection Act, the Clean Water Act, CERCLA, analogous state laws, and each of their implementing regulations. The United States Fish and Wildlife Service ("USFWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of, or harm to, species or damages to habitat or natural resources occur or may occur, government entities or at times private parties may act to restrict or prevent oil and gas exploration or production activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or production activities, including, for example, for releases of oil, wastes, hazardous substances, sediments, or other regulated materials, and may seek natural resources damages and, in some cases, criminal penalties. For example, the Dunes Sagebrush Lizard ("DSL") is one species that, if listed as endangered or threatened under the ESA, could impact our profitability. The DSL is found in southeastern New Mexico and adjacent portions of Texas. The USFWS proposed to list the DSL as endangered in July 2023. If the DSL is ultimately listed as an endangered or threatened species, operations in any area that is designated as the DSL's habitat may be limited, delayed or, in some circumstances, prohibited, and our operators could be required to comply with expensive mitigation measures intended to protect the dunes sagebrush lizard and its habitat.

The purpose of the Occupational Safety and Health Act ("OSHA"), comparable state statutes, and each of their implementing regulations is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act ("EPCRA"), and comparable state statutes and any implementing regulations thereof may require disclosure of information about hazardous materials stored, used, or produced in operations on the Properties and that such information be provided to employees, state and local governmental authorities, and/or citizens, as applicable.

These regulations and proposals and any other new regulations requiring the installation of more sophisticated pollution control equipment, additional evaluation or assessment, or more stringent permitting or environmental protection measures could have a material adverse impact on our business, results of operations, and financial condition.

Scrutiny of oil and natural gas production activities continues in other ways. The federal government has in recent years undertaken several studies of the oil and gas industry's potential impacts. For example, in 2016 the EPA published a final report of a four-year study focused on the possible relationship between hydraulic fracturing and drinking water. In its assessment, the EPA concluded that certain aspects of hydraulic fracturing, such as water withdrawals and wastewater management practices, could result in impacts to water resources, although the report did not identify a direct link between hydraulic fracturing and impacts to groundwater resources. In addition, in May 2022, the U.S. Government Accountability Office ("GAO") released a study on methane emissions from oil and gas development, which included a recommendation that the Bureau of Land Management ("BLM") consider whether to require gas capture plans, including gas capture targets, from operators on federal lands. The results of these studies or similar governmental reviews could spur initiatives to further regulate oil and gas production activities.

Several states, including states where the Properties are located, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado and Texas, have enacted bans on hydraulic fracturing. However, in May 2015, the Texas legislature enacted a bill preempting local bans on hydraulic fracturing. Colorado has also begun to increasingly regulate oil and gas operations with consideration towards GHG emissions and cumulative impacts. In January 2024, the Colorado Energy and Carbon Management Commission (formerly the Colorado Oil and Gas Conversation Commission) released draft rules that, if finalized as proposed, would require regulators to consider cumulative impacts of oil and gas operations in permitting decisions and increase scrutiny on the project's proximity to other industrial sites, residential and school areas, "disproportionately impacted communities," and "cumulatively impacted communities." The draft rules would also set GHG emissions intensity targets for oil and gas operators and require regulators to consider such targets in their cumulative impacts analysis, as well as the potential to restrict operations during the summer in Ozone Nonattainment Areas. We cannot predict whether other similar legislation in other states will ever be enacted and if so, what the provisions of such legislation 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 operating partners and our revenues and results of operations.

The National Environmental Policy Act ("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. If, for example, our third-party operating partners conduct activities on federal land, receive federal funding, or require federal permits, such activities may be covered under NEPA. Certain 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 some of the changes to NEPA enacted under the Trump Administration that were intended to streamline NEPA review (the "2020 NEPA Rule"). The April 2022 rule promulgation is considered phase one of a two-phase review of the 2020 NEPA Rule that was announced by the Biden Administration to emphasize the need to review federal actions for climate change and environmental justice impacts, among other factors. The Council on Environmental Quality ("CEQ") proposed the "Phase 2" revisions to NEPA in July 2023. These new and (if enacted) additional anticipated changes to the NEPA review process would affect the assessment of projects ranging from oil and natural gas leasing to development on public and Indian lands.

Climate Change

The energy industry is affected from time to time in varying degrees by political developments and a wide range of federal, tribal, state and local statutes, rules, orders and regulations that may, in turn, affect the operations and costs of the companies engaged in the energy industry. In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases ("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, which may include operations on the Properties. Further, the Inflation Reduction Act ("IRA"), which passed in August 2022, includes a charge for methane emissions from specific types of facilities that emit 25,000 metric tons of carbon dioxide equivalent or more per year, and, although the IRA generally provides for a conditional exemption under certain circumstances, the charge applies to emissions that exceed an established emissions threshold for each type of covered facility. The charge starts at $900 per metric ton of methane in 2025 (using 2024 data), and increases to $1,500 after two years. While Congress has from time to time considered legislation to reduce emissions of GHGs, in recent years there has not been significant activity at the federal level in the form of adopted legislation aimed at reducing GHG emissions.

In the absence of comprehensive federal climate legislation, 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. 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 it to incur costs to reduce emissions of GHGs associated with its operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and gas produced from the Properties. Restrictions on emissions of methane or carbon dioxide, such as restrictions on venting and flaring of natural gas or increased fuel or energy efficiency requirements, that may be imposed in various states, as well as state and local climate change initiatives, could adversely affect the oil and natural gas industry, and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact oil and natural gas assets.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as greenhouse gas cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there exists the United Nations-sponsored Paris Agreement, which is a non-binding agreement for nations to limit their greenhouse gas emissions through individually determined reduction goals every five years after 2020. While the United States under the Trump Administration withdrew from the Paris Agreement effective November 4, 2020, President Biden recommitted the United States to the Paris Agreement on January 20, 2021. In December 2023, the United Arab Emirates hosted the 28th session of the Conference of the Parties ("COP28") where parties signed onto an agreement 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. Finally, it should be noted that 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. In addition, spurred by increasing concerns regarding climate change, the oil and gas industry faces growing demand for corporate transparency and a demonstrated commitment to sustainability goals.

There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into non-fossil fuel related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. President Biden signed an executive order calling for the development of a "climate finance plan" and, separately, in late 2020, the Federal Reserve announced that it had joined the NGFS, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. In September 2022, the Federal Reserve announced that six of the U.S.' largest banks would participate in a pilot climate scenario analysis to enhance the ability of firms and supervisors to measure and manage climate-related risk. Taking place throughout 2023, the pilot exercise is designed to analyze the impact of both physical and transition risks related to climate change on specific assets of the banks' portfolios. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Environmental, social, and governance ("ESG") goals and programs, which typically include extralegal targets related to environmental stewardship, social responsibility, and corporate governance, have become an increasing focus of investors and stockholders across the industry. While reporting on ESG metrics is currently voluntary, access to capital and investors is likely to favor companies with robust ESG programs in place. Furthermore, in March 2022 the SEC proposed rule amendments that, if adopted, would require public companies to disclose certain climate-related information in their public filings. A final rule is expected in 2024. Similarly, certain states have enacted or are otherwise considering disclosure requirements for certain climate-related risks. Enhanced climate-related disclosure requirements could increase our operators' operating costs and lead to reputational or other harm with customers, regulators, or other stakeholders to the extent our, disclosures do not meet their own standards or expectations. Consequently, we are also exposed to increased litigation risks relating to alleged climate-related damages resulting from our operators' operations, statements alleged to have been made by us or others in our industry regarding climate change risks, or in connection with any future disclosures we may make regarding reported emissions, particularly given the inherent uncertainties and estimation required with respect to calculating and reporting GHG emissions. These rules, if adopted, along with increasing pressure related to ESG from the investor community could lead to increased operating costs that would materially adversely affect our operating partners and our revenues and results of 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.

In addition, the majority of scientific studies on climate change suggest that extreme weather conditions and other risks may occur in the future in the areas where we operate, although the scientific studies are not unanimous. Although operators may take steps to mitigate any such risks, no assurance can be given that they will not have material adverse effect on our business.

Human Capital Resources

As of December 31, 2023, we had two full time employees. We have an MSA with the Manager, pursuant to which the Manager provides general and administrative, engineering, land, contract administration, tax, accounting, legal and compliance services to us.

We believe, and the Manager believes, that our future success depends partially on our ability to attract, retain, and motivate qualified personnel. We and the Manager strive to provide employees with a rewarding work environment, including the opportunity for success and a platform for personal and professional development. Together with our Manager, we seek to provide a working environment that empowers employees, allows them to execute at their highest potential, keeps them safe, and promotes their professional growth. We and our Manager offer a competitive total rewards program to employees, comprised of base salary, short-term incentives tied to our performance, comprehensive employee benefits that include medical and dental coverage, and paid parental leave for both birth and non-birth parents. Our Manager also offers a 401(k) program, which includes fully-vested employer matched contributions. We believe that our values, rewarding work environment, and competitive pay help us retain our employees and those of our Manager and minimize employee turnover in a very challenging personnel market.

Office Locations, Internet Website and Availability of Public Filings

Our principal office is located at 5217 McKinney Avenue, Suite 400, Dallas, TX 75205. Our website address is www.graniteridge.com.

We share a portion of the Manager's office space (which consists of approximately 11,700 square feet), pursuant to the MSA. We believe our office space is sufficient to meet our needs and that additional office space can be obtained if necessary.

We furnish or file our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, our Current Reports on Form 8-K and amendments to such reports or other documents with the SEC under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). The SEC also maintains an internet website at www.sec.gov that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC.

We also make these documents available free of charge at www.graniteridge.com under the "Investors" link as soon as reasonably practicable after they are filed or furnished with the SEC.

Information on our website is not incorporated into this Annual Report or our other filings with the SEC and is not a part of them.

Item 1A. *Risk Factors*

The following risk factors apply to our business and operations. These risk factors are not exhaustive, and investors are encouraged to perform their own investigation with respect to our business, financial condition and prospects. You should carefully consider the following risk factors in addition to the other information included in this Annual Report, including matters addressed in the section entitled "Cautionary Note Regarding Forward-Looking Statements" and the financial statements and notes to the financial statements included herein. We may face additional risks and uncertainties *that are not presently known to us, or that we currently deem immaterial, which may also impair our business or financial condition. The following discussion should be read in conjunction with the financial statements and notes to the financial statements included herein. As used in the risks described in this subsection, references to "we," "us," "our" and the "Company" are intended to refer to Granite Ridge and its consolidated subsidiaries, unless the context clearly indicates otherwise.*

Risks Related to Our Business and Operations

As a non-operator, our development of successful operations relies extensively on third parties, which could have a material adverse effect on our results of operation.

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 operation would be materially adversely affected.

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 third-party operators could prevent us from realizing 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 industry 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.

These risks are heightened in a low commodity 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. Commodity prices and/or other conditions have in the past and may in the future cause oil and gas operators to file for bankruptcy. The insolvency of an operator of any of the Properties, the failure of an operator of any of the 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 gas leases jointly owned with the operator or another insolvent owner. Finally, an operator of the Properties may have the right, if another non-operator fails to pay its share of costs because of its insolvency or otherwise, to require us to pay its proportionate share of the defaulting party's share of costs.

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

Our exposures to credit risk, in part, are through receivables resulting from the sale of our oil and natural gas production, which operating partners 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 operating partners. This may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. A low commodity price environment may strain our operating partners, which could heighten this risk. The inability or failure of our operating partners to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

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, adverse weather events or natural disasters, equipment malfunctions or failures, scheduled or unscheduled maintenance, legal or other reasons, could result in a substantial increase in costs, declines in realized commodity prices, the shut-in of producing wells, or the delay or discontinuance of development plans for the Properties. 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 may 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 the 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 the Pipeline and Hazardous Materials Safety Administration, and therefore less capacity to transport our products by pipeline. Any significant curtailment in gathering system or transportation, processing, or refining-facility capacity could reduce our operating partners' ability to market oil production and have an adverse effect on us. Operators' access to transportation options and the prices they receive can also be affected by federal and state regulation — including regulation of oil production, transportation, and pipeline safety — as well as by general economic conditions and changes in supply and demand.

The loss of a key member of the Manager's 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.

We rely on continued contributions of the members of the Manager's management team by virtue of the MSA. Our success depends heavily upon the continued contributions of those members of the Manager's 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 the Manager's management team's knowledge and expertise in the industry. To continue to develop our business, we rely on the Manager's management team's knowledge and expertise in the industry and will use the Manager's management team's relationships with industry participants to enter into strategic relationships. The members of the Manager's management team may terminate their employment with the Manager at any time. If the Manager were to lose key members of its management team, neither the Manager nor we may be able to replace the knowledge or relationships that they possess, and our ability to execute our business plan could be materially harmed. As a result, our operations and financial condition could suffer.

Oil and natural gas prices are volatile. Extended declines in such 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 the oil and natural gas production associated with our working interests heavily influence our production, revenue, cash flows, profitability, reserve bookings and access to capital. Although we seek to mitigate volatility and potential declines in commodity prices through derivative arrangements that hedge a portion of the expected production associated with our working interests, this merely seeks to mitigate (not eliminate) these risks, and such activities come with their own risks.

The prices we receive for the production and the levels of the production associated with our working interests 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;
- 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 (such as the global COVID-19 coronavirus outbreak);
- 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, particularly those in the Middle East, Russia, South America and Africa;

- the outbreak or escalation of military hostilities, including between Russia and Ukraine, Israel and Hamas, continued instability in the Middle East, including from the Houthi rebels in Yemen, and the potential destabilizing effect such conflicts may pose for the European continent or the global oil and natural gas markets;
- the level of global oil and natural gas exploration, production activity and inventories;
- changes in U.S. energy policy;
- weather conditions and world health events;
- technological advances affecting energy consumption;
- domestic, local and foreign governmental taxes, tariffs and/or regulations;
- proximity and capacity of processing, gathering, storage, 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 commodity 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 any credit facilities (or other debt instruments) 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 operating partners’ 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 the operators of the Properties as a result of other factors, including:

- declines in oil or natural gas prices, as occurred in 2020 in connection with the COVID-19 pandemic;
- infrastructure limitations, such as gas gathering and processing constraints;
- the high cost, shortages or delays of equipment, materials and services;
- unexpected operational events, 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 service tools;
- compliance with environmental, health, safety 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 circulation;
- 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, regulatory penalties and third party claims. 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.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established or operations are commenced on units containing the acreage or the leases are extended.

A portion of our acreage is not currently held by production or held by operations. Unless production in paying quantities is established or operations are commenced on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to participate in the development of the related Properties. Drilling plans for these areas are generally in the discretion of third-party operators and are subject to change based on various factors that are beyond our control, such as: the availability and cost of capital, equipment, services and personnel; seasonal conditions; regulatory and third-party approvals; oil and natural gas prices; results of title work; gathering system and other transportation constraints; drilling costs and results; and production costs. As of December 31, 2023, we had leases that were not developed that represented 5,498 net acres potentially expiring in 2024, 1,459 net acres potentially expiring in 2025 and 491 net acres potentially expiring in 2026 and beyond.

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

An increase in commodity 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 operating partners' 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 commodity prices as producers seek to increase production in order to capitalize on higher commodity prices. In situations where cost inflation exceeds commodity 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 the drilling of new wells or significant increase in drilling costs could reduce our revenues and cash flows.

New technologies may cause the current exploration and drilling methods of our operating partners to become obsolete, and such operators may not be able to keep pace with technological developments in the oil and gas industry.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force our operating partners to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, and that may in the future, allow them to implement new technologies before we or our operating partners can. We cannot be certain that we or our operators will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If our operators are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

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

In 2020 and 2023, we were required to write down the carrying value of certain properties that constitute our oil and natural gas properties, and further writedowns could be required by us in the future. Under the successful efforts method of accounting, capitalized costs related to proved oil and natural gas properties, including wells and related support equipment and facilities, are evaluated for impairment on an annual basis, or more frequently if indicators of impairment exist. If undiscounted cash flows are insufficient to recover the net capitalized costs, an impairment charge for the difference between the net capitalized cost of proved properties and their estimated fair values is recognized. A substantial or extended decline in oil or natural gas prices, could result in future impairments of our proved oil and natural gas properties.

Our estimated 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 reserves.

Determining the amount of oil and natural gas recoverable from various formations involves significant complexity and uncertainty. No one can measure underground accumulations of oil or natural gas in an exact way. 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, exploration 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 and preparing reports to our lenders and investors, including estimates prepared by our independent reserve engineering firm. Although the reserve information contained herein is reviewed by our independent reserve engineers, estimates of crude oil and natural gas reserves are inherently imprecise. The process also requires economic assumptions about matters such as 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 estimated reserves relies in part on the ability of the Manager’s reserve engineers to make accurate assumptions. Any significant variance from these assumptions by actual figures could greatly affect our estimated 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 estimated reserves are based result in the actual quantities of oil and natural gas our operating partners ultimately recover being different from our estimated reserves. 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.

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 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 oil and natural gas 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. 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 our 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 future success depends on our ability to replace reserves that our operators produce.

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 exploration and 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. 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 exploratory 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 our initial investments. Additionally, we cannot assure you that unproved reserves or undeveloped acreage that we acquire will be profitably developed, that new wells drilled on the Properties will be productive or that we will recover all or any portion of our investments in the Properties and our reserves.

Extreme weather conditions could adversely affect operators' ability to conduct drilling activities in some of the areas where the Properties are located.

Drilling and producing activities and other operations in some of our operating areas could be adversely affected by extreme weather conditions, such as floods, lightning, drought, ice and other storms, prolonged freeze events, and tornadoes, which may cause a loss of production from temporary cessation of activity, or lost or damaged facilities and equipment on the part of our operating partners. Such extreme weather conditions could also impact other areas of operations for our operating partners, including access to drilling and production facilities for routine operations, maintenance and repairs and the availability of, and access to, necessary third-party services, such as electrical power, water, gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt operations on the affected Properties and materially increase operation and capital costs, which could have a material adverse effect on our business, 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 currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 42% of our estimated net proved reserves volumes were classified as proved undeveloped as of December 31, 2023. Development of these reserves may take longer and require higher levels of capital expenditures than we currently 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 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 fully assess their deficiencies and potential. Inspections are often not performed on properties being acquired, and environmental matters, such as subsurface contamination, are not necessarily observable even when an 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;
- 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 investment criteria. 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 cash flow. 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.

We may not be able to successfully integrate future acquisitions or realize all of the anticipated benefits from our future acquisitions, and our future results will suffer if we do not effectively manage our expanded operations.

Our growth strategy will, in part, rely on acquisitions. We have to plan and manage acquisitions effectively to achieve revenue growth and maintain profitability in our evolving market. Our future success will depend, in part, upon our ability to manage our expanded business, which may pose substantial challenges for management, including challenges related to the management and monitoring of new operations and basins and associated increased costs and complexity. We may also face increased scrutiny from governmental authorities as a result of increases in the size of our business. There can be no assurances that we will be successful or that we will realize the expected benefits currently anticipated from our acquisitions. In addition, the process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our and the Manager’s management may be required to devote considerable amounts of time to this integration process, which decreases the time they have to manage our business. If management is not able to effectively manage the integration process, or if any business activities are interrupted as a result of the integration process, our business could suffer.

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

Prior to drilling an oil or natural gas well, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review 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 preliminary 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. While we typically conduct title examination prior to our acquisition of oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights, any failure to obtain perfect title to our leaseholds may adversely affect our current production and reserves and our ability in the future to increase production and reserves.

Our derivatives activities could adversely affect our 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. In accordance with applicable accounting principles, we are required to record our derivatives at fair market value, and recognize all gains and losses on such instruments in earnings in the period in which they occur. 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 our estimates 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 commodity 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 may 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 our 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.

Decommissioning costs are unknown and may be substantial. Unplanned costs could divert resources from other projects.

We may become responsible for costs associated with plugging, abandoning and reclaiming wells, pipelines and other facilities that our operators use for production of oil and natural gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as “decommissioning.” We accrue a liability for decommissioning costs associated with our operators' wells but have not established any cash reserve account for these potential costs in respect of any of the Properties. If decommissioning is required before economic depletion of the Properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair our ability to focus capital investment in other areas of our business.

We are not insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of the Properties from operational loss-related events. We have insurance policies that include coverage for general liability, operational control of well, oil pollution, workers’ compensation and employers’ liability and other coverage. Our insurance coverage includes deductibles that have to be met prior to recovery, as well as sub-limits or self-insurance. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences, damages or losses.

We may be liable for damages from an event relating to a project in which we own a non-operating working interest. Such events may also cause a significant interruption to our business, which might also severely impact our financial position. We may experience production interruptions for which we do not have production interruption insurance.

We intend to reevaluate the purchase of insurance, policy limits and terms annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

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 with the relevant authorities.

Our competitors also include entities with greater technical, physical and financial resources. Finally, 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 our business. If we are unsuccessful in competing against other companies, our business, results of operations, financial condition or prospects could be materially adversely affected.

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

We and the Manager have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we and the Manager have developed or may develop proprietary software systems, management techniques and other information and operational technologies incorporating software licensed from third parties. It is possible that we, the Manager, or these third parties, could incur interruptions from cybersecurity attacks, computer viruses or malware, user error, or that third-party service providers could cause a breach of our data. We believe that we and the Manager have positive relations with their information and operational technology vendors; however, any interruptions to our or the Manager's arrangements with third parties for their computing, communications, or operational infrastructure or any other interruptions to, or breaches of, their information or operational systems could lead to data corruption, communication interruption, corruption or loss of sensitive or confidential information, misdirected wire transfers, and an inability to perform services for our customers; complete or settle transactions; maintain our books and records; prevent environmental damage; and maintain communications or operations; or otherwise significantly disrupt our business operations. Although we and the Manager utilize various procedures and controls designed to monitor these threats and mitigate their 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 or the Manager rely on, directly or indirectly, in the operation of our business (such as pipelines and other infrastructure) could suffer interruptions or breaches from cyberattacks or similar events that are entirely outside the control of us or the Manager, and any such events could significantly disrupt our business operations and/or have a material adverse effect on our results of operations. We have not, to our knowledge, experienced any material losses relating to cyberattacks; however, there can be no assurance that we will not suffer material losses in the future.

We are not able to anticipate, detect or prevent all cyberattacks, particularly because the methodologies used by attackers change frequently or may not be recognized until an attack is already underway or significantly thereafter, and because attackers are increasingly using technologies designed to circumvent cybersecurity measures and avoid detection. Cybersecurity attacks are also becoming more sophisticated and include, but are not limited to, ransomware, credential stuffing, spear phishing, social engineering, use of deepfakes (i.e., highly realistic synthetic media generated by artificial intelligence) and other attempts to gain unauthorized access to data for purposes of extortion or other malfeasance.

Additionally, as cyberattacks become more sophisticated, we may incur significant cost to upgrade or enhance our security measures and procedures to protect against such cyberattacks.

In addition, our operating partners 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 our 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 our operations to increased risks. Any future terrorist attack at our operating partners' facilities, or those of their purchasers or vendors, could have a material adverse effect on our financial condition and operations.

We are subject to various laws related to data privacy and cybersecurity. These data laws are not uniform and as the privacy legal landscape develops, we may need to incur additional costs to upgrade or enhance our compliance measures. Any failure or perceived failure by us, the Manager, or our third-party service providers to comply with such data privacy and cybersecurity laws or any unauthorized access or improper disclosure of our data could have a material adverse effect on our financial condition and operations.

A variety of stringent federal, tribal, state, and local laws and regulations govern the environmental aspects of the oil and gas business, and noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties, injunctive relief, or other liabilities.

A variety of stringent federal, tribal, state, and local laws and regulations govern the environmental aspects of the oil and gas business. Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties, injunctive relief, or other liabilities.

Additionally, compliance with these laws and regulations may, from time to time, result in increased costs of operations, delay in operations, or decreased production, and may affect acquisition costs. Examples of laws and regulations that govern the environmental aspects of the oil and gas business include the following:

- the CAA, which restricts the emission of air pollutants from many sources, imposes various pre-construction, operating, permitting monitoring, control, recordkeeping, and reporting requirements and is relied upon by the EPA as an authority for adopting climate change regulatory initiatives, including relating to GHG emissions;

- the CWA, which regulates discharges of pollutants and dredge and fill material to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction as protected waters of the United States;

- the OPA, which requires oil spill prevention, control, and countermeasure planning and imposes liabilities for removal costs and damages arising from an oil spill into waters of the United States;

- the SDWA, which protects the quality of the nation's public drinking water sources through adoption of drinking water standards and control over the subsurface injection of fluids into belowground formations;

- the CERCLA, which imposes liability without regard to fault on certain categories of potentially responsible parties including generators, transporters and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur, as well as on present and certain past owners and operators of sites were hazardous substance releases have occurred or are threatening to occur;

- the RCRA, which imposes requirements for the generation, treatment, storage, transport, disposal and cleanup of non-hazardous and hazardous wastes;

- the Endangered Species Act ("ESA"), which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating limitations or restrictions or a temporary, seasonal or permanent ban on operations in affected areas. Similar protections are afforded to migratory birds under the Migratory Bird Treaty Act ("MBTA") and bald and golden eagles under the Bald and Golden Eagle Protection Act ("BGEPA");

- the EPCRA, which requires certain facilities to report toxic chemical uses, inventories, and releases and to disseminate such information to local emergency planning committees and response departments; and
- the OSHA and comparable state statutes, which impose regulations related to the protection of worker health and safety, including requiring employers to implement a hazard communication program and disseminate hazard information to employees.

These U.S. laws and their implementing regulations, as well as state counterparts, generally restrict or otherwise regulate the management of hazardous substances and wastes, the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and groundwater, including through permitting requirements, monitoring and reporting requirements, limitations or prohibitions of operations on certain protected areas, requirements to install certain emissions monitoring or control equipment, spill planning and preparedness requirements, and the application of specific worker health and safety criteria (see Item 1. "Business - Governmental Regulation and Environmental Matters" and Item 1. "Business - Climate Change" for further discussion). Failure to comply with applicable environmental laws and regulations by us or third-party operators or contractors could trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements or other corrective measures, and the issuance of orders enjoining existing or future operations. In addition, we or our operating partners may be strictly liable under state or federal laws for environmental damages caused by the previous owners or operators of properties they purchase, without regard to fault.

Environmental laws and regulations change frequently and tend to become more stringent over time, and the implementation of new, or the modification of existing, laws or regulations could adversely affect our business. For example, in recent years, the EPA published final rules that establish new air emission control requirements, among other requirements, for oil and natural gas production, processing, transportation, and storage activities to address emissions of methane and VOCs. Among these requirements is the reduction of methane and VOC emissions from oil and gas wells through the use of reduced emission completions or “green completions” on all hydraulically fractured wells subject to the rule. These NSPSs, as so referred, also impose requirements for leak detection and repair at well sites and natural gas transmission compressor stations and professional engineer certifications of emission control systems installed to comply with the rule. These rules have been heavily litigated and some aspects of them continue to be subject to various challenge, rescission, and proposal actions. Accordingly, the final implementation and scope of these requirements remains uncertain, but the imposition of these requirements on certain sources of air emissions in the oil and gas industry that were constructed, reconstructed, or modified on or after August 23, 2011, will likely result in increased costs for oil and natural gas exploration and production activities. In December 2023, the EPA finalized more stringent methane rules for new, modified, and reconstructed facilities, known as OOOOb, as well as standards for existing sources for the first time ever, known as OOOOc. Under the final rules, states have two years to prepare and submit their plants to impose methane emission controls on existing sources. The presumptive standards established under the final rule are generally the same for both new and existing sources and include enhanced leak detection survey requirements using optical gas imaging and other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of emissions by 95% through capture and control systems, zero-emission requirements for certain devices, and the establishment of a “super emitter” response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and repair requirements. Fines and penalties for violations of these rules can be substantial. It is likely, however, that the final rule and its requirements will be subject to legal challenges. The requirements of the EPA’s final methane rules have the potential to increase the operating costs of our operators and thus may adversely affect our financial results and cash flows. Moreover, failure to comply with these CAA requirements can result in the imposition of substantial fines and penalties as well as costly injunctive relief. These rules could further increase the cost of development and operation of the Properties.

Additionally, some states in which the Properties are located, such as Colorado and New Mexico, have adopted stringent rules and regulations to reduce methane emissions and emissions of other hydrocarbons, VOCs, and nitrogen oxides associated with oil and gas facilities. For example, the Colorado Department of Public Health and Environment’s Air Quality Control Commission (“AQCC”) recently adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, the development of pre-production air monitoring plans at certain oil and gas facilities, enclosed combustion device testing, a methane intensity reduction requirement based on statewide volume of production and additional measures for reducing and eliminating emissions from pneumatic devices. AQCC is expected to undertake several additional rulemaking efforts to further reduce emissions over the next several years. Additionally, the Colorado Energy and Carbon Management Commission is currently reviewing draft rules that would consider the cumulative impacts of air emissions from oil and gas projects in permitting decisions. State rules and regulations such as these could significantly increase the costs to develop and operate the Properties, result in a delay in operations or decreased production, and may affect acquisition costs.

We anticipate that hydraulic fracturing will be engaged in by some or all opportunities in which we invest, which could be adversely affected by regulatory initiatives related to hydraulic fracturing.

Hydraulic fracturing is an important and commonly used process that we anticipate will be engaged in by some or all opportunities in which it invests. Hydraulic fracturing is used to stimulate production of natural gas and/or oil from dense subsurface rock formations.

The EPA has asserted authority over certain hydraulic-fracturing activities that use diesel fuel under the SDWA. In addition, legislation such as the Fracturing Responsibility and Awareness of Chemicals Act and similar proposals have been repeatedly introduced before Congress to provide for federal regulation of hydraulic fracturing, such as through disclosure requirements for chemical additives used in hydraulic fracturing fluids. Certain states (including states in which the Properties are located) have adopted, and other states are considering adopting, regulations that could impose more stringent permitting and well construction requirements on hydraulic-fracturing operations or seek to ban fracturing activities altogether. For example, Colorado Senate Bill 19-181 amended state law to give municipalities and counties greater local control over siting and permitting of oil and gas facilities, and some municipalities within the state have implemented regulations within their jurisdictions. In the event federal, tribal, state, local, or municipal legal restrictions are adopted in our target areas, the investments may incur significant additional compliance costs, experience delays in exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. A number of governmental bodies, including the EPA, a committee of the U.S. House of Representatives, the U.S. Department of Energy, and a number of other federal agencies have from time to time analyzed, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. As these studies proceed, and depending on their scope and results, they could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory programs. This, in turn, could lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing, which could adversely affect the investments.

Seismicity concerns associated with injection of produced water and certain other field fluids into disposal wells has led to increased regulation of saltwater injection and disposal wells in certain areas of states in which the Properties are located, which could increase the cost of, or limit the number of facilities available for, disposal of produced water from oil and gas exploration and production operations at the Properties.

Flowback and produced water or certain other field fluids gathered from oil and natural gas exploration and production operations are often injected or disposed of in underground disposal wells. This disposal process has been linked to increased induced seismicity events in certain areas of the country. Certain states (including states in which the Properties are located) have begun to consider or adopt laws and regulations that may restrict or otherwise prohibit oilfield fluid disposal in certain areas or in underground disposal wells, and state agencies implementing these requirements may issue orders directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations or impose standards related to disposal well construction and monitoring. For example, the Colorado Oil and Gas Conservation Commission adopted regulations in November 2020 that impose various new requirements on the underground injection of fluid wastes to further seismic safety and protection of the environment. In addition, in 2014, the RRC published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the RRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. Furthermore, in response to a number of earthquakes in recent years in the Midland Basin, in September 2021 the RRC announced that it will not issue any new SWD well permits in the SRA area, and will require existing SWD wells in that area to reduce their maximum daily injection rate to 10,000 barrels per day per well. In December 2021, the RRC went on to suspend all well activity in deep formations in the Gardendale SRA, effectively terminating 33 disposal well permits. And in October 2021 and January 2022, respectively, the RRC identified two additional SRAs: the Northern Culberson-Reeves SRA and the Stanton SRA. Operators in the Northern Culberson-Reeves and Stanton SRAs were required to develop and implement seismic response plans, which include expanded data collection efforts, contingency responses for future seismicity, and scheduled checkpoint updates with RRC staff. In December 2023, the RRC suspended the permits of 23 deep disposal wells in a seismic response area in the Northern Culberson-Reeves SRA. Such restrictions and requirements could limit oil and gas well exploration and production activities underlying the investments or increase the cost of those activities if wastewater disposal options become limited (see Item 1. "Business - Governmental Regulation and Environmental Matters - Environmental Matters" for further discussion).

Specific climate legislation and regulation regarding emissions of carbon dioxide, methane, and other greenhouse gases may develop or be enacted, which could adversely affect the oil and gas industry and demand for the oil and gas produced from the Properties.

The energy industry is affected from time to time in varying degrees by political developments and a wide range of federal, tribal, state and local statutes, rules, orders and regulations that may, in turn, affect the operations and costs of the companies engaged in the energy industry. 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, which may include operations on the Properties. Further, the IRA, which the U.S. Congress passed in August 2022, includes a charge for methane emissions from specific types of facilities that emit 25,000 metric tons of carbon dioxide equivalent or more per year, and although the IRA generally provides for a conditional exemption under certain circumstances, the charge applies to emissions that exceed an established emissions threshold for each type of covered facility. The charge starts at $900 per metric ton of methane in 2025 (using 2024 data), and increases to $1,500 after two years. Additional GHG regulation could also result from the agreement crafted during the United Nations climate change conference in Paris, France in December 2015 (the “Paris Agreement”). Under the Paris Agreement, the United States committed to reducing its GHG emissions by 26-28% by the year 2025 as compared with 2005 levels. Moreover, in November 2021, at the U.N. Framework Convention on Climate Change 26th Conference of the Parties, the U.S. and the European Union advanced a Global Methane Pledge to reduce global methane emissions at least 30% from 2020 levels by 2030, which over 100 countries have signed. Additionally, in December 2023, the United Arab Emirates hosted COP28 where parties signed onto an agreement 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.

In the absence of comprehensive federal climate legislation, 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.

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. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and gas produced from the Properties. Restrictions on emissions of methane or carbon dioxide, such as restrictions on venting and flaring of natural gas, that may be imposed in various states, as well as state and local climate change initiatives, such as increased energy efficiency standards or mandates for renewable energy sources, could adversely affect the oil and gas industry, and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact oil and gas assets. Finally, it should be noted that 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 us.

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. ESG goals and programs, which may include extralegal targets related to environmental stewardship, social responsibility, and corporate governance, have become an increasing focus of investors and stakeholders across the industry, and companies without robust ESG programs may find access to capital and investors more challenging in the future. Further, while reporting on most ESG information is currently voluntary, in March 2022, the SEC issued a proposed rule that would require public companies to disclose certain climate-related information, including climate-related risks, impacts, oversight and management, financial statement metrics and emissions, targets, goals and plans. While the proposed rule is not yet effective, compliance with the proposed rule as drafted could result in increased legal, accounting and financial compliance costs, make some activities more difficult, time-consuming and costly, and place strain on our personnel, systems and resources.

Fuel and energy conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry could reduce demand for oil and natural gas.

Fuel and energy conservation 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 electric vehicles, wind, solar, geothermal, tidal, fuel cells and biofuels) could reduce demand for oil and natural gas and, therefore, our revenues.

Additionally, certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and natural gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations. Furthermore, certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas exploration and production and related infrastructure projects. With the continued volatility in oil and natural gas prices, and the possibility that interest rates will continue to rise in the future, 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 may impact our business.

Increasing attention to climate change, fuel conservation measures, alternative fuel requirements, incentives to conserve energy or use alternative energy sources, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on our access to capital markets. Increasing attention to climate change and any related negative public perception regarding us and/or our industry, for example, may result in demand shifts for our products, increased litigation risk for us, and increased regulatory, legislative and judicial scrutiny, which may, in turn, lead to new state, local, tribal and federal safety and environmental laws, regulations, guidelines and enforcement interpretations.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their 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, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may, of their own accord, elect not to provide or place additional restrictions on funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

We rely on the Manager for various certain key services under the MSA, which could result in conflicts of interest and other unforeseen risks.

Under the MSA with the Manager, our success depends upon the Manager who will have overall supervision and control certain business affairs of us and our investment activities. Further, the employees of the Manager and its respective principals and managers (as applicable) will devote a portion of their time to the affairs of our business for the proper performance of their duties. However, other investment activities of the Manager are likely to require those individuals to devote substantial amounts of their time to matters unrelated to our business. Pursuant to the MSA, we will be offered the opportunity to participate in certain of these activities.

The MSA provides for the Manager to offer us the opportunity to participate in certain investments made by funds affiliated with the Manager and for us to offer such funds the opportunity to participate in certain investments made by us. The Manager may make investments on behalf of its funds that are not a part of our Company or in which such funds may co-invest with us, any such transactions may involve conflicts of interest among us, the Manager, and their affiliates, some or all of which may not be thought of or taken into account in reviewing and approving such transactions. In certain events, the Manager may not be in a position unilaterally to control such investments or exercise certain rights associated with such investments. We may be subject to conflicts of interest involving the Manager and its affiliates, and the Manager may enter into relationships with developers, co-owners or other affiliates, some of which may give rise to conflicts of interest. To the extent not addressed by the MSA, we and the Manager intend to implement policies as necessary or appropriate to deal with such potential conflicts.

Investment analyses and decisions by the Manager may frequently be required to be undertaken on an expedited basis to take advantage of investment opportunities. In such cases, the information available at the time of making an investment decision may be limited, and the Manager may not have access to complete information regarding the investment. Therefore, no assurance can be given that the Manager will have knowledge of all circumstances that may adversely affect an investment. In addition, the Manager expects to rely upon specialized expert input by various third-party consultants and service providers in connection with its evaluation of proposed investments.

Additionally, if the MSA is terminated or not renewed upon the end of its term, it may be difficult for us to hire the necessary personnel in a timely manner to handle the matters and services being provided by the Manager, which could have a material adverse effect on our business and results of operations.

Certain of our unaudited financial statements for the three and nine months ended September 30, 2022 were required to be restated, and our management identified material weaknesses in our internal control over financial reporting. Management implemented steps that remediated these material weaknesses effective as of December 31, 2023. These steps may, however, not be sufficient to prevent a future weakness. A material weakness may result in a misstatement of accounts or disclosures that would result in a material misstatement of the Company's financial statements that would not be prevented or detected on a timely basis or cause us to fail to meet our obligations under securities laws, stock exchange listing rules, or debt instrument covenants to file periodic financial reports on a timely basis.

Our management and audit committee concluded that our previously issued unaudited condensed combined financial statements as of and for the three and nine month periods ended September 30, 2022, included in the Company's Quarterly Report on Form 10-Q filed on November 14, 2022 (the "Original Form 10-Q"), were materially misstated. Management and the audit committee concluded that these financial statements should no longer be relied upon. We filed Amendment No. 1 to the Original Form 10-Q on March 10, 2023 in order to correct the errors by restating our previously issued unaudited condensed combined financial statements as of and for the three and nine month periods ended September 30, 2022.

In connection with the restatement, the Company's management has evaluated the impact of these errors on its assessment of the design and operating effectiveness of the Company's internal control over financial reporting. In addition, management concluded that as of December 31, 2022, the Company did not have effective controls over Information Technology General Controls ("ITGC") pertaining to user access management. As a result, the Company's management identified material weaknesses in its internal control over financial reporting due to the lack of effectively designed controls over proper review of the depletion calculation and the accounting for acquisitions and the related allocation and classification of consideration paid to proved and unproved properties and user access. A material weakness is defined as a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. If not remediated, the material weaknesses could result in further material misstatements in our consolidated financial statements.

Management implemented steps that remediated these material weaknesses effective as of December 31, 2023. These steps may, however, not be sufficient to prevent a future weakness. A material weakness may result in a misstatement of accounts or disclosures that would result in a material misstatement of the Company's financial statements that would not be prevented or detected on a timely basis or cause us to fail to meet our obligations under securities laws, stock exchange listing rules, or debt instrument covenants to file periodic financial reports on a timely basis. Any of these failures could result in adverse consequences that could materially and adversely affect the Company's business, including an adverse impact on the market price of our common stock, potential action by the SEC, stockholder lawsuits, delisting of the Company's stock, and general damage to our reputation. The Company could incur additional costs to rectify any new issues that may emerge, and the existence of these issues could adversely affect our reputation or investor perceptions. The additional reporting and other obligations resulting from such issues, including any litigation or regulatory inquires that may result therefrom, could increase legal and financial compliance costs and the costs of related legal, accounting and administrative activities.

We rely to a large degree on the Manager to maintain an effective system of internal control over financial reporting and we may not be able to accurately report our financial results or prevent fraud.

Under the terms of the MSA, we must rely to a large extent on the internal controls and financial reporting controls of the Manager, and the Manager's failure to maintain effective controls or comply with applicable standards may adversely affect us. On March 3, 2023, the Audit Committee of our Board of Directors concluded that our previously issued unaudited condensed combined financial statements as of and for the three and nine month periods ended September 30, 2022, included in the Company's Quarterly Report on Form 10-Q filed on November 14, 2022 were materially misstated. In addition, the Company did not have effective controls over ITGC pertaining to user access management. In connection with the material misstatement and lack of effective user access controls, our Company's management identified material weaknesses in our disclosure controls and internal control over financial reporting.

In addition, any failure of the Manager to remediate any identified material weakness, or any future failure of the Manager to maintain adequate internal controls over financial reporting or to implement required, new or improved controls, or difficulties encountered in their implementation, could cause additional material weaknesses or significant deficiencies in our financial reporting and could result in errors or misstatements in our consolidated financial statements that could be material. Any third-party failure to achieve and maintain effective internal controls could have a material adverse effect on our business, our ability to access capital markets and investors' perception of us. Additionally, if we or our independent registered public accounting firm were to conclude that third-party internal controls over financial reporting were not effective, any material weaknesses in such internal controls could require significant expense and management time to remediate.

The relative lack of public company experience by our management team may put us at a competitive disadvantage.

As a company with a class of securities that are registered under the Exchange Act, we are subject to reporting and other legal, accounting, corporate governance, and regulatory requirements imposed by the Exchange Act or the Sarbanes-Oxley Act. With the exception of our Chief Financial Officer and Chief Accounting Officer, Granite Ridge's management team lacks public company experience, which could impair our ability to comply with these legal, accounting, and regulatory requirements. Such responsibilities include complying with securities laws and making required disclosures on a timely basis. Our senior management may not be able to implement and effect programs and policies in an effective and timely manner that adequately respond to such increased legal and regulatory compliance and reporting requirements. Our failure to do so could lead to the imposition of fines and penalties and negatively impact our business and operations.

The borrowing base under our Credit Agreement may be reduced in light of commodity price declines, which could limit us in the future.

At the closing of the Business Combination, we entered into a Credit Agreement, secured by a first priority mortgage and security interest in substantially all of our assets and our restricted subsidiaries. Availability under the Credit Agreement is limited to the aggregate commitments of the lenders, which is the least of the aggregate maximum credit amounts of the lenders, the borrowing base and the elected commitment amount chosen by us and, in the case of an elected commitment increase, consented to by the increasing lender(s). Our borrowing base under the Credit Agreement will depend on, among other things, the value of the proved reserves attributed to, and projected revenues from, the oil and natural gas properties securing our Credit Agreement, many of which factors are beyond our control. Accordingly, lower commodity volumes and prices may reduce the available amount of our borrowing base under the Credit Agreement. Our borrowing base is determined at the discretion of the lenders party to the Credit Agreement and is subject to semi-annual redeterminations, as well as any special redeterminations described in the Credit Agreement. We may reset the elected commitment amount under the Credit Agreement in conjunction with each borrowing base redetermination. Upon a redetermination of the borrowing base, if borrowings in excess of the revised borrowing capacity are outstanding, we would be required to repay the excess or otherwise remedy the deficiency in accordance with the terms of the Credit Agreement. We may not have sufficient funds to make such repayments, and may not have access to the equity or debt capital markets, at the time such repayment obligations are due. If we do not have sufficient funds and are otherwise unable to raise sufficient funds, negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results. Please see the section entitled *"Management's Discussion and Analysis of Results of Operations and Financial Condition — Liquidity and Capital Resources — Granite Ridge Credit Agreement"* for more information.

Risks Relating to Ownership of Our Common Stock

Sales of our common stock by our securityholders (or the perception that such shares may be sold) or issuances by us may cause the market price of our securities to drop significantly, even if our business is doing well.

The sale of shares of our common stock in the public market, or the perception that such sales could occur, could harm the prevailing market price of shares of our common stock. These sales, or the possibility that these sales may occur, also might make it more difficult for us to sell equity securities in the future at a time and at a price that it deems appropriate.

In addition, the shares of our common stock reserved for future issuance under the Granite Ridge 2022 Omnibus Incentive Plan (the “Incentive Plan”) will become eligible for sale in the public market once those shares are issued, subject to provisions relating to various vesting requirements and, in some cases, limitations on volume and manner of sale applicable to affiliates under Rule 144. The maximum number of shares of our common stock reserved for issuance to directors, officers, employees and consultants or advisors employed by or providing service to the Company under our equity incentive plans is 6.5 million, which represented approximately 4.9% of the shares of our common stock outstanding following the consummation of the Business Combination. As of December 31, 2023, the Company had 5.7 million shares of common stock remaining available for future awards under the Incentive Plan. We have filed a registration statement on Form S-8 under the Securities Act of 1933, as amended (the "Securities Act") to register shares of our common stock or securities convertible into or exchangeable for shares of our common stock issued pursuant to the Incentive Plan. Accordingly, shares registered under such registration statements are available for sale in the open market.

In the future, we may also issue securities in connection with investments or acquisitions. The amount of shares of our common stock issued in connection with an investment or acquisition could constitute a material portion of our then-outstanding shares of common stock. Any issuance of additional securities in connection with investments or acquisitions may result in additional dilution to our stockholders and may have an adverse effect on the price of shares of our common stock.

We qualify as an “emerging growth company” within the meaning of the Securities Act and avail ourselves of certain exemptions from disclosure requirements available to emerging growth companies, which could make our securities less attractive to investors and may make it more difficult to compare our performance to the performance of other public companies.

We qualify as an “emerging growth company” as defined in Section 2(a)(19) of the Securities Act, as modified by the Jumpstart Our Business Startups Act of 2012 (the “JOBS Act”). As such, we are eligible for and take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies for as long as we continue to be an emerging growth company, including, but not limited to, (i) not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, (ii) reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements and (iii) exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. As a result, our stockholders may not have access to certain information they may deem important. We will remain an emerging growth company until the earliest of the last day of the fiscal year (a) following September 18, 2025, (b) in which we have total annual gross revenue of at least $1.235 billion or (c) in which we are deemed to be a large accelerated filer, which means (1) the market value of our common stock that is held by non-affiliates exceeds $700 million as of the last business day of our most recently completed second fiscal quarter (2) has been subject to compliance with periodic reporting requirements for a period of at least 12 months, and (3) the date on which we have issued more than $1.0 billion in non-convertible debt securities during the prior three year period. We cannot predict whether investors will find our securities less attractive because it will rely on these exemptions. If some investors find our securities less attractive as a result of our reliance on these exemptions, the trading prices of our securities may be lower than they otherwise would be, there may be a less active trading market for our securities and the trading prices of our securities may be more volatile.

Further, Section 102(b)(1) of the JOBS Act exempts emerging growth companies from being required to comply with new or revised financial accounting standards until private companies (that is, those that have not had a Securities Act registration statement declared effective or do not have a class of securities registered under the Exchange Act) are required to comply with the new or revised financial accounting standards. We take advantage of the benefits of such extended transition period, which means that when a standard is issued or revised and we have different application dates for public or private companies, we, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard. This may make comparison of our financial statements with another public company which is neither an emerging growth company nor an emerging growth company which has opted out of using the extended transition period difficult or impossible because of the potential differences in accounting standards used.

If the Business Combination’s benefits do not meet the expectations of financial analysts, the market price of our common stock may decline.

The market price of our common stock may decline if we do not achieve the perceived benefits of the Business Combination as rapidly, or to the extent anticipated by, financial analysts or the effect of the Business Combination on our financial results is not consistent with the expectations of financial analysts. Accordingly, holders of our common stock may experience a loss as a result of a decline in the market price of our common stock. In addition, a decline in the market price of our common stock could adversely affect our ability to issue additional securities and to obtain additional financing in the future.

Future issuances of debt securities and/or equity securities may adversely affect us, including the market price of our common stock, and may be dilutive to our existing stockholders.

In the future, we may incur debt and/or issue equity ranking senior to our common stock. Those securities will generally have priority upon liquidation. Such securities also may be governed by an indenture or other instrument containing covenants restricting our operating flexibility. Additionally, any convertible or exchangeable securities that we issue in the future may have rights, preferences and privileges more favorable than those of our common stock. Because our decision to issue debt and/or equity in the future will depend, in part, on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing, nature or success of our future capital raising efforts. As a result, future capital raising efforts may reduce the market price of our common stock and be dilutive to our existing stockholders.

Anti-takeover provisions in our organizational documents could delay or prevent a change of control.

Certain provisions of our amended and restated certificate of incorporation and our amended and restated bylaws may have an anti- takeover effect and may delay, defer or prevent a merger, acquisition, tender offer, takeover attempt or other change of control transaction that a stockholder might consider in their best interest, including those attempts that might result in a premium over the market price for the shares held by our stockholders. These provisions, among other things:

- establish a staggered board of directors divided into three classes serving staggered three-year terms, such that not all members of our Board will be elected at one time;
- authorize our Board to issue new series of preferred stock without stockholder approval and create, subject to applicable law, a series of preferred stock with preferential rights to dividends or our assets upon liquidation, or with superior voting rights to existing common stock;
- eliminate the ability of stockholders to call special meetings of stockholders;
- eliminate the ability of stockholders to fill vacancies on our Board;
- establish advance notice requirements for nominations for election to our Board or for proposing matters that can be acted upon by stockholders at annual stockholder meetings;
- permit our Board to establish the number of directors;
- provide that our Board is expressly authorized to make, alter or repeal our amended and restated bylaws;
- provide that stockholders can remove directors only for cause; and
- limit the jurisdictions in which certain stockholder litigation may be brought.

These anti-takeover provisions could make it more difficult for a third-party to acquire us, even if the third party’s offer may be considered beneficial by many of our stockholders. As a result, our stockholders may be limited in their ability to obtain a premium for their shares. These provisions could also discourage proxy contests and make it more difficult for you and other stockholders to elect directors of your choosing and to cause us to take other corporate actions you desire.

Our amended and restated certificate of incorporation contains a provision renouncing our interest and expectancy in certain corporate opportunities.

Our amended and restated certificate of incorporation provides that we, to the fullest extent provided by law, renounce any expectancy that our directors or officers will offer to us any corporate opportunity to which it becomes aware, except to the extent such corporate opportunity was offered to such person solely in his or her capacity as a director or officer of ours. Officers and directors, including those nominated by the funds managed by Grey Rock or its affiliates, may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to affiliates (subject to the MSA that sets forth an allocation of certain acquisition opportunities between us and funds associated with the Manager) or other businesses in which they have invested or are otherwise associated, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities, possibly causing these opportunities to not be available to us or causing them to be more expensive for us to pursue. In addition, Grey Rock and its affiliates, may dispose of properties or other assets in the future, without any obligation to offer us the opportunity to purchase any of those assets. As a result, our renouncing of our interest and expectancy in any business opportunity that may be from time to time presented our officers and directors, could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for us. We cannot assure you that any conflicts that may arise between us and any of such parties, on the other hand, will be resolved in our favor. As a result, competition from Grey Rock and its affiliates or businesses associated with our other officers and directors could adversely impact our results of operations.

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, employees or stockholders.

Our amended and restated certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, that the Court of Chancery shall, to the fullest extent permitted by law, be the sole and exclusive forum for any stockholder (including a beneficial owner) to bring any derivative action on our behalf, any action asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of ours, any action asserting a claim against us, our directors, officers or employees arising pursuant to any provision of the DGCL or our amended and restated certificate of incorporation or our amended and restated bylaws, or any action asserting a claim against us, our directors, officers or employees governed by the internal affairs doctrine, in each case subject to the Court of Chancery having personal jurisdiction over any indispensable parties (or such parties consent to the personal jurisdiction of the Court of Chancery within ten days following the Court of Chancery's determination as to such personal jurisdiction) and subject matter jurisdiction over the claim. The foregoing forum selection provision shall not apply to claims arising under the Exchange Act, the Securities Act, or any other claim for which the federal courts have exclusive jurisdiction.

In addition, our amended and restated certificate of incorporation provides that the federal district courts of the United States will be the exclusive forum for resolving any complaint asserting a cause of action arising under the Securities Act; however, there is uncertainty as to whether a court would enforce such provision. Although we believe these provisions benefit us by providing increased consistency in the application of Delaware law for the specified types of actions and proceedings, the provisions may have the effect of discouraging lawsuits against us or our directors and officers.

Alternatively, if a court were to find the choice of forum provision contained in our amended and restated certificate of incorporation to be inapplicable or unenforceable in an action, we may incur additional costs associated with resolving such action in other jurisdictions, which could harm our business, financial condition, and operating results. For example, under the Securities Act, state and federal courts have concurrent jurisdiction over all suits brought to enforce any duty or liability created by the Securities Act, and investors cannot waive compliance with the federal securities laws and the rules and regulations thereunder. Any person or entity purchasing or otherwise acquiring any interest in our common stock shall be deemed to have notice of and consented to this exclusive forum provision, but will not be deemed to have waived our compliance with the federal securities laws and the rules and regulations thereunder.

We are a "controlled company" under the corporate governance rules of the NYSE and, as a result, qualifies for exemptions from certain corporate governance requirements. We rely on certain of these exemptions, which means you will not have the same protections afforded to stockholders of companies that are subject to such requirements.

Grey Rock Energy Fund III-A, LP, Grey Rock Energy Fund III-B, LP, and Grey Rock Energy Fund III-B Holdings, LP and their affiliates (collectively, "Grey Rock Fund III") collectively own a majority of our voting common stock. As a result, following the Business Combination, we are a "controlled company" within the meaning of the corporate governance standards of the rules of the NYSE. Under these rules, a listed company of which more than 50% of the voting power is held by an individual, group or another company is a "controlled company" and may elect not to comply with certain corporate governance requirements, including:

- the requirement that a majority of our Board of Directors consist of independent directors;

- the requirement that our director nominations be made, or recommended to the full Board of Directors, by our independent directors or by a nominations committee that is comprised entirely of independent directors and that we adopt a written charter or board resolution addressing the nominations process; and

- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

As long as we remain a "controlled company," we may elect to take advantage of any of these exemptions. Our Board of Directors does not have a majority of independent directors, our compensation committee does not consist entirely of independent directors and does not have a nominating committee. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the rules of the NYSE.

Changes in applicable tax laws or interpretations thereof or the imposition of new or increased taxes or fees may increase our future tax liabilities and adversely affect our operating results and cash flows.

We are subject to various complex and evolving U.S. federal, state and local tax laws. U.S. federal, state and local tax laws, policies, statutes, rules, regulations or ordinances could be interpreted, changed, modified or applied adversely to us (in each case, possibly with retroactive effect). For example, the IRA resulted in fundamental changes to the U.S. Internal Revenue Code, as amended, including, among many other things, a 15% corporate alternative minimum tax on certain large corporations, a nondeductible 1% excise tax on the value of certain stock that a company repurchases, and various tax incentives for energy and climate initiatives. In addition, from time to time, U.S. federal and state level legislation has been proposed that that would, if enacted into law, make significant changes to tax laws, including to certain key U.S. federal and state income tax provisions currently applicable to natural gas and oil exploration and development companies. Such proposed legislative changes include, but are not limited to, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies and (v) an increase in the U.S. federal income tax rate applicable to corporations. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Further, 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 changes in tax laws or the imposition of new or increased taxes or fees could increase our future tax liabilities and adversely affect our operating results and cash flows.

In addition, our effective tax rate and tax liability are based on the application of current income tax laws, regulations and treaties. These laws, regulations and treaties are complex and often open to interpretation. In the future, the tax authorities could challenge our interpretation of laws, regulations and treaties, resulting in additional tax liability or adjustment to our income tax provision that could increase our effective tax rate which could adversely affect our operating results and cash flows. Changes to tax laws may also adversely affect our ability to attract and retain key personnel.

General Risks

The market price of shares of our common stock may be volatile.

Fluctuations in the price of our securities could contribute to the loss of all or part of your investment. The trading price of our securities could be volatile and subject to wide fluctuations in response to various factors, some of which are beyond our control. Price volatility may be greater if the public float and trading volume of our common stock is low.

Any of the factors listed below could have a material adverse effect on your investment. Our securities may trade at prices significantly below the price you paid for them. In such circumstances, the trading price of our securities may not recover and may experience a further decline. Factors affecting the trading price of our securities may include:

- actual or anticipated fluctuations in our quarterly financial results or the quarterly financial results of companies perceived to be similar to us;

- changes in the market's expectations about our operating results;

- lack of adjacent competitors;

- our operating results failing to meet the expectation of securities analysts or investors in a particular period;
- changes in financial estimates and recommendations by securities analysts concerning us or the industries in which we operate in general;
- operating and stock price performance of other companies that investors deem comparable to us;
- announcements by us or our competitors of significant contracts, acquisitions, joint ventures, other strategic relationships or capital commitments;
- changes in laws and regulations affecting our business;
- commencement of, or involvement in, litigation involving us;
- changes in our capital structure, such as future issuances of securities or the incurrence of additional debt;
- the volume of shares of our common stock available for public sale;
- any significant change in our Board of Directors or management;
- speculation by the press or investment community;
- sales of substantial amounts of our common stock by our directors, executive officers or significant stockholders or the perception that such sales could occur;
- general economic and political conditions such as recessions, interest rates, fuel prices, international currency fluctuations and acts of war or terrorism; and
- changes in accounting standards, policies, guidelines, interpretations or principles.

Broad market and industry factors may materially harm the market price of our securities irrespective of our operating performance. The stock market in general and the NYSE have experienced price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of the particular companies affected.

The ongoing military conflicts between Ukraine and Russia, Israel and Hamas, and continued instability in the Middle East, including from the Houthi rebels in Yemen, has caused unstable market and economic conditions and is expected to have additional global consequences, such as heightened risks of cyberattacks. Our business, financial condition, and results of operations may be materially adversely affected by the negative global and economic impact resulting from these conflicts or any other geopolitical tensions.

Worldwide economic, political and military events, including war, terrorist activity, and events in the Middle East, have contributed, and are likely to continue to contribute, to oil and natural gas price volatility. For example, the ongoing armed conflicts between Russia and Ukraine and Israel and Hamas and the continuation of, and the escalation in the severity of, these conflicts has led to extreme regional instability, caused dramatic fluctuations in global financial markets and has increased the level of global economic uncertainty, including uncertainty about world-wide oil supply and demand, which in turn has caused increased volatility in commodity prices. Further, the Houthi movement, which controls parts of Yemen, has targeted and launched numerous attacks on Israeli, American and international commercial marine vessels in the Red Sea as the ships approach the Suez Canal, resulting in many shipping companies re-routing to avoid the region altogether and worsening existing supply chain issues, including delays in supplier deliveries, extended lead times and increased cost of freight, impacts to the shipping of oil and gas, insurance and materials. The potential for conflict with Iran, a major oil producer, the Houthi movement in Yemen or the Hezbollah movement in Lebanon has increased as a result of continued, increasing hostilities in the Middle East.

In addition, the United States and other countries have imposed sanctions on Russia which increases the risk that Russia, as a retaliatory action, may launch cyberattacks against the United States, its government, infrastructure and businesses. On March 21, 2022, the Biden Administration issued warnings about the potential for Russia to engage in malicious cyber activity against the United States in response to the economic sanctions that have been imposed.

The extent and duration of the military action, sanctions and resulting market disruptions are impossible to predict, but could be substantial. Prolonged unfavorable economic conditions or uncertainty as a result of the military conflict in the Middle East 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.

World health events may materially adversely affect our business.

World health events may cause disruptions to our business and operational plans, which may include (i) shortages of employees or partners, (ii) unavailability of contractors and subcontractors, (iii) interruption of supplies from third parties upon which we rely, (iv) recommendations of, or restrictions imposed by, government and health authorities, including quarantines, and (v) restrictions that we and our partners impose, including facility shutdowns, to ensure the safety of employees and others. While it is not possible to predict their extent or duration, these disruptions may have a material adverse effect on our business, financial condition and results of operations.

Further, the effects of a world health event could negatively impact global demand for crude oil and natural gas, which may contribute to volatility that could impact the price we and our partners receive for oil and natural gas and materially and adversely affect the demand for and marketability of production, as well as lead to temporary curtailment or shut-ins of production due to lack of downstream demand or storage capacity. Additionally, to the extent a pandemic, epidemic or outbreak of an infectious disease adversely affects our business and financial results, it may also have the effect of heightening many of the other risks set forth in this Item 1A. “Risk Factors.”

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 financial condition and results of operations.

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. Most recently, on March 10, 2023, Silicon Valley Bank (“SVB”) was closed by the California Department of Financial Protection and Innovation, which appointed the Federal Deposit Insurance Corporation (“FDIC”) as receiver. Similarly, on March 12, 2023, Signature Bank and Silvergate Capital Corp. were each swept into receivership. Although a statement by the Department of the Treasury, the Federal Reserve and the FDIC indicated that all depositors of SVB would have access to all of their money after only one business day of closure, including funds held in uninsured deposit accounts, borrowers under credit agreements, letters of credit and certain other financial instruments with SVB, Signature Bank or any other financial institution that is placed into receivership by the FDIC may be unable to access undrawn amounts thereunder. Access to funding sources and other credit arrangements could be significantly impaired by factors that affect the financial services industry or economy in general. These factors could include, among others, events such as liquidity constraints or failures, the ability to perform obligations under various types of financial, credit or liquidity agreements or arrangements, disruptions or instability in the financial services industry or financial markets, or concerns or negative expectations about the prospects for companies in the financial services industry.

In addition, investor concerns regarding the U.S. or international financial systems could result in less favorable commercial financing terms, including higher interest rates or costs and tighter financial and operating covenants, or systemic limitations on access to credit and liquidity sources, thereby making it more difficult to acquire financing on acceptable terms or at all. Any decline in available funding or access to our cash and liquidity resources could, among other risks, adversely impact our ability to meet our financial or other obligations. Any of these impacts, or any other impacts resulting from the factors described above or other related or similar factors, could have material adverse impacts on our liquidity and our business, financial condition or results of operations.

Item 1B. ***Unresolved Staff Comments***

None.

Item 1C. ***Cybersecurity***

Risk Management and Strategy

We recognize the importance of implementing and maintaining measures to safeguard our information technology systems and data. We and the Manager have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we and the Manager have developed or may develop proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. The Company integrates cybersecurity risks into its overall enterprise risk management program. Pursuant to the MSA, the Manager provides us with back-office services, including services for the management of our data and cybersecurity risk. Together with the Manager, we seek to assess, identify, and manage cybersecurity risks with the help of independent cybersecurity services as follows: (i) we have a multi-layered system designed to protect and monitor data and cybersecurity risk, which includes the use of firewalls and protection software, and an independent cybersecurity vendor regularly assesses our cybersecurity safeguards and updates our cybersecurity infrastructure, procedures, policies, and education programs, as appropriate; (ii) we have monitoring and detection systems designed to identify cybersecurity incidents, and we have an incident response plan designed to provide action to contain cybersecurity incidents, mitigate their impact, and restore our normal operations; (iii) we require our employees and contractors to receive annual cybersecurity awareness training and incident response plan training; and (iv) we have access controls designed to provide users of the systems containing our data with access consistent with the principle of least privilege, which requires that users be given no more access than necessary to complete their job functions.

The Manager engages an independent cybersecurity vendor to review, assess, and make recommendations regarding our information security program and information technology strategic plan. We recognize that third-party service providers introduce cybersecurity risks. In an effort to mitigate these risks, before engaging with any third-party cybersecurity service provider, we conduct due diligence to evaluate their cybersecurity capabilities. Additionally, we endeavor to require third-party service providers with access to personally identifiable information to adhere to our security standards and protocols.

Impact of Risks from Cybersecurity Threats

As of the date of this Annual Report, though the Company and our service provider have experienced certain minor cybersecurity incidents, we are not aware of any previous cybersecurity threats or incidents that may have materially affected or are reasonably likely to materially affect the Company. However, 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 cyberattack will not occur. A successful attack on our information technology systems could have significant consequences to the business. While we devote resources to our security measures to protect our systems and information, these measures cannot provide absolute security. No security measure is infallible. See Item 1A. “Risk Factors” for additional information about the risks to our business associated with a breach or compromise to our information technology systems.

Board of Directors’ Oversight and Management’s Role

The Board of Directors has primary oversight of risks from cybersecurity threats and recognizes the importance of cybersecurity to the success and resilience of our business. The Board of Directors delegates oversight of our enterprise risk management process, including review of cybersecurity and data protection and compliance with cybersecurity policies, to the Audit Committee. An employee of the Manager is responsible for day to day oversight of our cybersecurity risks and management of our cybersecurity vendor, and that employee escalates higher business cybersecurity risks to the Audit Committee or the Board as appropriate.

Company management meets as needed with relevant employees of the Manager to discuss cybersecurity risks and incident trends and escalates them, as appropriate, to the Audit Committee.

Item 2. ***Properties of Granite Ridge***

Unless the context otherwise requires, with respect to descriptions of the financials and operations of the properties owned by Granite Ridge, references to “Granite Ridge”, the “Company”, “we”, “us”, or “our” refer to Granite Ridge Resources, Inc. and its consolidated subsidiaries. The following discussion of our properties should be read in conjunction with the accompanying audited consolidated financial statements and related notes included elsewhere in this Annual

Report. Please see the section entitled "Management's Discussion and Analysis of Results of Operations and Financial Condition — Results of Operations" for information on our production, prices, and production cost.

Estimated Net Proved Reserves

The tables below summarize our estimated net proved reserves at December 31, 2023, based on reports prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), our third-party independent reserve engineers. In preparing its reports, NSAI evaluated properties representing all of our proved reserves at December 31, 2023 in accordance with the rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities. 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. All of our proved reserves are located in the United States. The following table sets forth summary information by reserve category with respect to estimated proved reserves at December 31, 2023:

	SEC Pricing Proved Reserves(1)					
	Reserve Volumes				PV-10(3)	
Reserve Category	Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)(2)	%	Amount (in thousands)	%
Proved developed producing	14,947	96,746	31,071	58 %	$ 616,220	72 %
Proved developed non-producing	25	87	40	— %	1,218	— %
Proved undeveloped	12,345	60,095	22,361	42 %	238,990	28 %
Total proved	27,317	156,928	53,472	100 %	$ 856,428	100 %
Total proved developed	14,972	96,833	31,111	58 %	$ 617,438	72 %

(1) The SEC Pricing Proved Reserves table above values oil and natural gas reserve quantities and related discounted future net cash flows as of December 31, 2023 based on average prices of $78.21 per barrel of oil and $2.64 per MMbtu of natural gas. Under SEC guidelines, these prices represent the average prices per barrel of oil and per MMbtu of natural gas at the beginning of each month in the 12-month period prior to the end of the reporting period. These prices are adjusted for location and quality differentials.

(2) Boe are computed based on a conversion ratio of one Boe for each barrel of oil and one Boe for every 6,000 cubic feet (i.e., 6 Mcf) of natural gas.

(3) Pre-tax PV10% or "PV-10", is a non-GAAP financial measure and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable U.S. GAAP measure. The amounts disclosed in the table above include net abandonment costs of $22.7 million as of December 31, 2023. See "Reconciliation of PV-10 to Standardized Measure" below.

The table above assumes prices and costs discounted using an annual discount rate of 10% without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or federal income taxes. The information in the table above does not give any effect to or reflect our commodity derivatives.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable U.S. GAAP financial measure for proved reserves calculated using SEC pricing. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 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 net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. Moreover, U.S. GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves or for reserves calculated using prices other than SEC prices. 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 of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of the pre-tax PV10% value of our SEC Pricing Proved Reserves as of December 31, 2023, 2022 and 2021 to the Standardized Measure of Discounted Future Net Cash Flows.

Standardized Measure Reconciliation

	December 31,		
(in thousands)	**2023**	**2022**	**2021**
Pre-tax present value of estimated future net revenues (Pre-Tax PV10%)	$ 856,428	$ 1,559,123	$ 778,230
Future income taxes, discounted at 10%	(134,520)	(293,196)	(3,879)
Standardized measure of discounted future net cash flows	$ 721,908	$ 1,265,927	$ 774,351

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 average 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 the Properties will vary from reserve estimates.

See Note 2 of the Notes to the Consolidated Financial Statements for additional discussion of our proved reserves.

Proved Undeveloped Reserves

At December 31, 2023, we had approximately 22,361 MBoe of proved undeveloped reserves as compared to 19,648 MBoe at December 31, 2022. A reconciliation of the change in proved undeveloped reserves during 2023 is as follows:

	MBoe
Estimated proved undeveloped reserves at December 31, 2022	19,648
Extensions and discoveries	11,144
Acquisition of reserves	4,207
Divestiture of reserves	(496)
Conversion to proved developed reserves	(9,562)
Revisions of previous estimates	(2,580)
Estimated proved undeveloped reserves at December 31, 2023	22,361

- *Extensions and discoveries*. In 2023, proved undeveloped reserves increased by 11,144 MBoe as a result of new proved undeveloped locations added primarily in the Permian Basin.

- *Acquisition of Reserves*. In 2023, acquisitions of proved undeveloped reserves of 4,207 MBoe were primarily attributable to the acquisitions of oil and natural gas properties in the Permian Basin. See Note 5 of the Notes to Consolidated Financial Statements for additional discussion of acquisitions during 2023.

- *Conversion to proved developed reserves.* In 2023, development of oil and natural gas properties resulted in the conversion of 9,562 MBoe from proved undeveloped reserves to proved developed reserves. During the year ended December 31, 2023, we incurred development costs of approximately $79 million related to these locations.

- *Revisions of previous estimates*. In 2023, revisions of previous estimates decreased proved undeveloped reserves by 2,580 MBoe primarily due to the removal of undeveloped drilling locations as they were no longer expected to be developed within five years of their initial recognition as well as lower oil and natural gas prices.

All of our recorded proved undeveloped reserves are scheduled to be drilled within five years of the date of their initial recognition.

At December 31, 2023, the PV-10 value of our proved undeveloped reserves amounted to 28% of the PV-10 value of our total proved reserves. There are numerous uncertainties regarding the proved and 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, drilling of obligatory wells, satisfactory rates of return on proposed drilling projects, and the levels of drilling activities by operators in areas where we hold leasehold interests. With 72% 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. Based on SEC pricing as of December 31, 2023, estimated future development costs required for the development of proved undeveloped reserves are projected to be approximately $343.9 million over the next five years.

Independent Petroleum Engineers

We have engaged NSAI to independently prepare our estimated net proved reserves. NSAI is a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical expert primarily responsible for preparing the estimates set forth in the NSAI 2023 Reserve Report is Mr. Nathan Shahan. Mr. Shahan, a Licensed Professional Engineer in the State of Texas (No. 102389), has been practicing consulting petroleum engineering at NSAI since 2007 and has over 5 years of prior industry experience. He graduated from Texas A&M University in 2002 with a Bachelor of Science Degree in Petroleum Engineering and in 2007 with a Master of Engineering Degree in Petroleum Engineering. Mr. Shahan meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. He is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers.

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 (except to the extent a contract specifically provides for escalation).

The reserves set forth in the NSAI report for the 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. The estimates of the reserves, future production, and income attributable to Properties are prepared using widely industry-accepted petroleum economic software packages, as well as NSAI's own proprietary petroleum economic software.

To estimate economically recoverable oil and natural gas reserves and related future net cash flows, we consider 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 NSAI 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 "*Risk Factors — Our estimated 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 reserves*."

Internal Controls Over Reserves Estimation Process

Pursuant to the MSA, the Manager provides us with engineering services. The Manager employs an internal reservoir engineering department which is led by the Manager's Executive Vice President (EVP) — Engineering, who is responsible for overseeing the internal preparation of our reserves pursuant to the MSA. The Manager's EVP — Engineering has a degree in petroleum engineering from the University of Calgary, and has over 20 years of oil and gas experience, with more than 15 years focused on reservoir engineering.

The Manager's technical team 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 the Manager's prescribed internal control procedures. The Manager's internal controls over the reserves estimation process includes inter-departmental verification of input data into the Manager's reserves evaluation software 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 in the Manager's reserves database;
- Review of working interests and net revenue interests in the Manager's reserves database against the Manager's well ownership system;
- Review of historical realized prices and differentials from index prices as compared to the differentials used in the Manager's reserves database;
- Review of updated projected capital costs for upcoming projects;
- Review of internal reserve estimates by well and by area by the Manager's reservoir engineers;
- Discussion of material reserve variances among the Manager's reservoir engineer and our executive management; and
- Review of a preliminary copy of the reserve report by our management.

Selected Oil and Natural Gas Information

Production, Price and Cost Data

The price that the Company receives for the oil and natural gas it produces is largely a function of market supply and demand. Demand has historically been affected by global economic conditions, including recession concerns, conflicts involving oil producing regions, and weather and other seasonal conditions. The following table sets forth production, price and cost data with respect to the Company's properties. These amounts represent the Company's historical results of operations without making pro forma adjustments for any acquisitions, divestitures or drilling activity that occurred during the respective years. Due to normal production declines, increases or decreases in drilling activity and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Year Ended December 31,		
	2023	2022	2021
Net Production:			
Oil (MBbl)	4,162	3,656	3,413
Natural gas (MMcf)	28,266	21,351	14,861
Total (MBoe)(1)	8,873	7,215	5,890
Average Daily Production:			
Oil (Bbl)	11,404	10,016	9,351
Natural gas (Mcf)	77,442	58,496	40,715
Total (Boe)(1)	24,311	19,765	16,137
Average Sales Prices:			
Oil (per Bbl)	$ 76.18	$ 92.50	$ 63.70
Natural gas and related product sales (per Mcf)	2.72	7.46	5.04
Realized price (per Boe)	44.41	68.94	49.27
Costs and Expenses (per Boe):			
Lease operating expenses	$ 6.82	$ 6.19	$ 4.47
Production and ad valorem taxes	$ 3.12	$ 4.24	$ 3.07
Depletion and accretion	$ 18.11	$ 14.66	$ 16.07
General and administrative	$ 3.15	$ 1.97	$ 1.73

(1) Natural gas is converted to Boe using the ratio of one barrel of oil to six Mcf of natural gas.

Drilling and Development Activities

The following table sets forth the number of gross and net productive wells drilled in the years ended December 31, 2023, 2022 and 2021. The number of wells drilled refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated. As a non-operator, we do not invest in exploratory wells, and instead invest exclusively in development wells. While there is the potential that development wells may yield dry holes, we have not encountered this, other than mechanical dry holes. Therefore, drilling activity related to exploratory wells and dry holes was not applicable to us in the years presented below.

	December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Productive development wells	314	24.55	265	20.78	213	14.18
Dry development wells (1)	2	0.57	—	—	—	—

(1) The dry hole category includes 2 (0.57 net) wells that were unsuccessful due to mechanical issues for the years ended December 31, 2023.

At December 31, 2023, we had 212 gross (15.99 net) wells for which drilling was either in-progress or were pending completion. These wells are not included in the table above.

The following table summarizes our cumulative gross and net productive oil and natural gas wells by basin at December 31, 2023. A significant majority of our wells in the Permian, Bakken, and DJ Basins are classified as oil wells, although they also produce natural gas and condensate. All of our wells in the Haynesville Basin are classified as natural gas wells. Our wells within the Eagle Ford Basin are classified as either oil or natural gas wells.

	December 31, 2023					
	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian	575	1	576	46.30	—	46.30
Eagle Ford	120	93	213	24.80	6.90	31.70
Bakken	938	—	938	39.00	—	39.00
Haynesville	—	117	117	—	16.40	16.40
DJ	967	15	982	42.20	0.90	43.10
Total	2,600	226	2,826	152.30	24.20	176.50

The following table summarizes our cumulative gross and net productive oil and natural gas wells by basin at December 31, 2022:

	December 31, 2022					
	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian	448	2	450	40.82	0.02	40.84
Eagle Ford	105	81	186	19.08	4.26	23.34
Bakken	907	1	908	37.73	0.20	37.93
Haynesville	—	62	62	—	12.18	12.18
DJ	681	70	751	16.43	2.16	18.59
Total	2,141	216	2,357	114.06	18.82	132.88

The following table summarizes our cumulative gross and net productive oil and natural gas wells by basin at December 31, 2021:

	December 31, 2021					
	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian	307	1	308	26.09	0.19	26.28
Eagle Ford	95	72	167	16.38	3.80	20.18
Bakken	866	1	867	35.96	0.20	36.16
Haynesville	—	53	53	—	9.43	9.43
DJ	557	68	625	14.50	2.09	16.59
Total	1,825	195	2,020	92.93	15.71	108.64

Developed and Undeveloped Acreage

The following table summarizes our estimated gross and net developed and undeveloped acreage by area at December 31, 2023.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Permian	44,738	6,462	6,166	3,131	50,904	9,593
Eagle Ford	24,025	3,936	6,587	2,873	30,612	6,809
Bakken	169,897	13,167	320	320	170,217	13,487
Haynesville	49,248	5,077	9,262	425	58,510	5,502
DJ	21,564	2,086	—	—	21,564	2,086
Total:	309,472	30,728	22,335	6,749	331,807	37,477

Acreage Expirations

As a non-operator, we are subject to lease expirations if an operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage summarized in the table below will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or some other "savings clause" is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have been commenced. While we generally expect to establish production from most of our acreage prior to expiration of the applicable lease terms, there can be no guarantee they can do so. The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2023 by area:

	2024		2025		2026 and Thereafter	
	Gross	Net	Gross	Net	Gross	Net
Permian	2,245	2,147	3,352	1,229	1,680	455
Eagle Ford(1)	6,305	2,845	—	—	282	28
Bakken	320	320	—	—	—	—
Haynesville	4,549	186	3,859	230	854	8
DJ	—	—	—	—	—	—
Total:	13,419	5,498	7,211	1,459	2,816	491

(1) These acres are subject to continuous drilling obligations.

The expired acreage was not material to our capital deployed on an aggregate basis across the Properties. Any proved undeveloped reserves associated with expiring acreage are expected to be drilled prior to the expiration of the respective leases.

Recent Acquisitions

We generally assess acreage and other acquisition opportunities subject to near-term drilling activities on a lease-by-lease or well-by-well basis because we believe each acquisition opportunity is best assessed on that basis if development timing is sufficiently clear. Consistent with that approach, a significant portion of our acquisitions involve properties that are selected by us on a lease-by-lease or well-by-well basis for their participation in a well expected to be developed in the near future, and the subject leases or wells are then aggregated to complete one single closing with the transferor. As such, we generally view each acreage or well assignment from sellers as involving several separate acquisitions combined into one closing with the common transferor for convenience. However, in certain instances an acquisition may involve a larger number of leases presented by the transferors as a single package without negotiation on a lease-by-lease or well-by-well basis. In those instances, we, together with the Manager, still review each lease and drilling opportunity on a lease-by-lease basis and well-by-well basis to ensure that the package as a whole meets our acquisition criteria and drilling expectations. See Note 5 of the Notes to the Consolidated Financial Statements regarding our recent acquisition activity.

Item 3. ***Legal Proceedings***

Our Company was not a party to any material legal proceedings during the year ended December 31, 2023. In the future, the Company may be subject from time to time to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

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

Market Information

Our common stock is listed and traded on the New York Stock Exchange under the symbols "GRNT".

As of March 5, 2024, there were 74 holders of record of our common stock.

Dividend Policy

We expect that Granite Ridge will pay quarterly cash dividends totaling approximately $60 million per fiscal year. For information about dividends, see "Item 8. Financial Statements and Supplementary Data."

Repurchases of Equity Securities

In December 2022, the Company announced that its Board of Directors approved a share repurchase program for up to $50.0 million of the Company's common. The stock repurchase program terminated on December 31, 2023.

The following table sets forth our share repurchase activity for each period presented:

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans	Approximate dollar value of shares that may yet be purchased under the plans or programs (in millions)
October 1, 2023 - October 31, 2023	1,009,656	$ 6.14	1,009,656	$ —
November 1, 2023 - November 30, 2023	1,316,575	$ 6.15	1,316,575	$ —
December 1, 2023 - December 31, 2023	1,510,969	$ 6.10	1,510,969	$ —

Item 6. [RESERVED]

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our financial statements and related notes included elsewhere in this Annual Report on Form 10-K.

The information in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" reflects the following: (1) as it pertains to periods prior to the completion of the Business Combination, the accounts of each of the Funds (as defined below) and all related wholly owned subsidiaries, and Granite Ridge Resources, Inc. For these periods, the Funds have been presented on a combined historical basis due to their prior common ownership and control; and (2) as it pertains to the periods subsequent to the completion of the Business Combination, the accounts of Granite Ridge Resources, Inc. as well as its wholly owned subsidiaries which include, Granite Ridge Holdings, LLC (formerly known as GREP Holdings, LLC) and Executive Network Partnership Corporation ("ENPC"), and all other subsidiaries created in connection with the Business Combination.

The following discussion contains "forward-looking statements" reflecting our current expectations, estimates and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this report. Please read "Cautionary Note Regarding Forward-Looking Statements." Also, please read the risk factors and other cautionary statements described under "Part I, Item 1A. Risk Factors." We assume no obligation to update any of these forward-looking statements, except as required by applicable law.

Overview

Granite Ridge is a scaled, non-operated oil and gas exploration and production company. We own a portfolio of wells and top-tier acreage across the Permian and four other prolific unconventional basins across the United States. Rather than drill wells ourselves, we increase asset diversity and decrease overhead by investing in a smaller piece of a larger number of high-graded wells drilled by proven public and private operators. As a non-operating partner, we pay our pro rata share of expenses, but we are not burdened by long-term contracts and drilling obligations common to operators.

As of December 31, 2023, we owned an interest in 2,826 gross (176.50 net) producing wells, 309,472 gross (30,728 net) developed acres, and 22,335 gross (6,749 net) undeveloped acres, all located in the United States.

Our average daily production for the year ended December 31, 2023 was 24,311 Boe per day.

The financial results presented in this section consist of the historical results of the combined Funds (as defined below), which at the closing of the Business Combination effectively became the historical results of Granite Ridge. Annual information related to the Results of Operations for Granite Ridge as of and for the years ended December 31, 2021 and 2020 were derived from the audited consolidated financial statements of Grey Rock Energy Fund, L.P., a Delaware limited partnership ("Fund I"), and the related notes, and the audited combined financial statements of Grey Rock Energy Fund II, L.P., a Delaware limited partnership ("Fund II-A"), Grey Rock Energy Fund II-B, L.P., a Delaware limited partnership ("Fund II-B") and Grey Rock Energy Fund II-B Holdings, L.P., a Delaware limited partnership ("Fund II-B Holdings", and together with Fund II-A and Fund II-B, collectively, "Fund II"), and Grey Rock Energy Fund III-A, L.P., a Delaware limited partnership ("Fund III-A"), Grey Rock Energy Partners Fund III-B ,L.P., a Delaware limited partnership ("Fund III-B"), and Grey Rock Energy Fund III-B Holdings, L.P., a Delaware limited partnership ("Fund III-B Holdings" and together with Fund III-A and Fund III-B, collectively, "Fund III" or "Predecessor") and the related notes included in the Company's amended registration statement on Form S-4 (File No. 333-264986) filed with the SEC on September 12, 2022. Fund I, Fund II and Fund III are collectively referred to herein as, the "Funds."

Business Combination

On October 24, 2022 (the "Closing Date"), Granite Ridge and ENPC consummated the business combination pursuant to the terms of the Business Combination Agreement, dated as of May 16, 2022 (the "Business Combination Agreement"), by and among ENPC, Granite Ridge, ENPC Merger Sub, Inc., a Delaware corporation and a wholly-owned subsidiary of Granite Ridge ("ENPC Merger Sub"), GREP Merger Sub, LLC, a Delaware limited liability company and a wholly-owned subsidiary of Granite Ridge ("GREP Merger Sub"), and Granite Ridge Holdings, LLC, a Delaware limited liability company formerly known as GREP Holdings, LLC, ("GREP").

Pursuant to the Business Combination Agreement, on the Closing Date, (i) ENPC Merger Sub merged with and into ENPC (the "ENPC Merger"), with ENPC surviving the ENPC Merger as a wholly-owned subsidiary of Granite Ridge and (ii) GREP Merger Sub merged with and into GREP (the "GREP Merger," and together with the ENPC Merger, the "Mergers"), with GREP surviving the GREP Merger as a wholly-owned subsidiary of Granite Ridge (the transactions contemplated by the foregoing clauses (i) and (ii) the "Business Combination," and together with the other transactions contemplated by the Business Combination Agreement, the "Transactions").

For additional information on the Business Combination See Note 1 in the Notes to the Consolidated Financial Statements.

Source of Our Revenues

We derive our revenues from our interests in the sale of oil and natural gas production. Revenues are a function of production, the prevailing market price at the time of sale, oil quality, and transportation costs to market. We use derivative instruments to hedge future sales prices on a portion of our oil and natural gas production. 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

Lease operating expenses

Lease operating expenses are the costs incurred in the operation of producing properties, including workover costs. Expenses for field employees' salaries, saltwater disposal, repairs and maintenance comprise the most significant portion of our lease operating expenses. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. A portion of our operating cost components are variable and change in correlation to production levels.

Production and ad valorem taxes

Production taxes are paid on produced oil and natural gas. Ad valorem taxes are paid on the value of our properties in certain states. 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 and accretion expense

Depletion and accretion include the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. As a "successful efforts" company, we capitalize all costs associated with our acquisition and successful development efforts and allocate these costs to each unit of production using the units of production method. Accretion expense relates to the passage of time of our asset retirement obligations.

Impairment expense

We evaluate capitalized costs related to proved and unproved oil and natural gas properties, including wells and related oil sales support equipment and facilities, for impairment on an annual basis, or more frequently if indicators of impairment exist. If undiscounted cash flows are insufficient to recover the net capitalized costs of proved properties, we recognize an impairment charge for the difference between the net capitalized cost of proved properties and their estimated fair values. Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects.

General and administrative expenses

General and administrative expenses include overhead, including payroll and benefits for our corporate staff, management and annual service fees under the MSA, audit and other professional fees and legal compliance.

Interest expense

We finance a portion of our working capital requirements, capital expenditures and acquisitions with borrowings. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions.

Gain (loss) on derivative contracts

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

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 and natural gas;
- the quantity of oil and natural gas production from the wells in which we participate;
- changes in the fair value of the derivative instruments we use to reduce our exposure to fluctuations in the price of oil and natural gas;
- 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 in the Eagle Ford, Permian, Bakken, Haynesville and Denver-Julesburg 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.

The price of oil and natural gas can vary depending on the market in which it is sold and the means of transportation used to transport the oil and natural gas to market.

The price at which our oil and natural gas production is sold typically reflects either a premium or discount to the NYMEX benchmark price. Thus, our operating results are also affected by changes in the oil and natural gas price differentials between the applicable benchmark and the sales prices we receive for our oil and natural gas production.

Our oil price differential to the NYMEX benchmark price during 2023, 2022 and 2021 was $(1.40) per barrel, $(1.89) per barrel and $(5.00) per barrel, respectively. Our natural gas price differential during 2023, 2022 and 2021 was $0.19 per Mcf, $0.91 per Mcf and $1.32 per Mcf, respectively.

Market Conditions

The price that we receive for the oil and natural gas our operators produce is largely a function of market supply and demand. Because our oil and natural 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. Worldwide supply in terms of output, especially production from properties within the United States, the production quota set by OPEC, and the strength of the U.S. dollar can adversely impact oil prices.

Historically, commodity prices have been volatile, and we expect the volatility to continue in the future.

Although we cannot predict the occurrence of events that may affect future commodity prices, or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business.

Prices for various quantities of natural gas and oil that we produce significantly impact our revenues and cash flows. The following table lists average NYMEX prices for oil and natural gas for the years ended December 31, 2023, 2022 and 2021.

	December 31,		
	2023	2022	2021
Average NYMEX Prices (1)			
Oil (per Bbl)	$ 77.58	$ 94.39	$ 68.07
Natural gas (per Mcf)	2.53	6.55	3.72

(1) Based on average NYMEX closing prices.

2023 Significant Events

Warrant Exchange

On June 22, 2023, we completed an exchange offer to holders of our outstanding warrants, which provided such holders the opportunity to receive 0.25 shares of our common stock in exchange for each warrant tendered by such holders (the "Offer"). This Offer coincided with a solicitation of consents from holders of the warrants to amend that certain Warrant Agreement, dated as of September 15, 2020, by and between Executive Network Partnering Corporation, a Delaware corporation ("ENPC"), and Continental Stock Transfer & Trust Company, as warrant agent ("Continental"), as amended on March 24, 2021, by and between ENPC and Continental, and as assigned pursuant to the Assignment, Assumption and Amendment Agreement, dated as of October 24, 2022, by and between Granite Ridge, ENPC and Continental (as amended and assigned, the "Warrant Agreement") to permit the Company to require that each warrant that remained outstanding upon the closing of the Offer be exchanged for 0.225 shares of our common stock (together with the Offer, the "Warrant Exchange"). On June 22, 2023, we issued 2,471,738 shares of common stock in exchange for 9,887,035 warrants tendered in the Offer, with a minimal cash settlement in lieu of partial shares. We also received the necessary approval from the holders of our outstanding warrants to amend the Warrant Agreement and accordingly, in July 2023, each remaining outstanding warrant was converted into 0.225 shares of the Company's common stock, and subsequently, no warrants remained outstanding. See Note 9 in the Notes to Consolidated Financial Statements for further discussion of the Warrant Exchange.

Distribution and Voting Agreement

On August 25, 2023, Fund III, which collectively owned a majority of the voting shares of our common stock, distributed an aggregate of 31,649,616 shares of our common stock, pro rata to its limited partners (the "Distribution"). As a result of the Distribution, Fund III's aggregate ownership of shares of our common stock was reduced from approximately 71% to approximately 47% as of the date of the Distribution.

Also on August 25, 2023, Grey Rock Energy Partners GP III, L.P., a Delaware limited partnership (who has voting and dispositive power over Granite Ridge common stock owned by Fund III and certain of its affiliates) ("GREP GP III"), Grey Rock Energy Partners GP II, L.P., a Delaware limited partnership (who has voting and dispositive power over Granite Ridge common stock owned by Fund II) ("GREP GP II"), and Matthew Miller, Griffin Perry, Thaddeus Darden and Kirk Lazarine (collectively, the "Voting Agreement Parties"), entered into a Stockholder Voting Agreement (the "Voting Agreement").

Pursuant to the Voting Agreement, the Voting Agreement Parties irrevocably and unconditionally agreed to vote the 75,957,927 shares of our common stock which the Voting Agreement Parties then held (and any other shares of our common stock obtained by Voting Agreement Parties in the future) at any annual or special meeting of our stockholders or in connection with any written consent of our stockholders. The 75,957,927 shares held by the Voting Agreement Parties as of the date of the Voting Agreement constituted approximately 56.3% of the total outstanding shares of our common stock as of such date. The Voting Agreement continues indefinitely, but can be terminated on 30 days' prior written notice by Voting Agreement Parties holding a majority of the shares of Granite Ridge common stock subject to the Voting Agreement. In connection with their entry into the Voting Agreement, the Voting Agreement Parties provided GREP GP III an irrevocable voting proxy to vote the shares subject to the Voting Agreement. Additionally, during the term of such agreement, the Voting Agreement Parties agreed not to transfer the shares covered by the Voting Agreement without the consent of GREP GP III, except pursuant to certain limited exceptions. Due to the Voting Agreement, GREP GP III, LLC, a Delaware limited liability company, the sole general partner of GREP GP III, has voting and dispositive power over a majority of the shares of the Company due to its ability to vote the outstanding shares of Granite Ridge common stock held by the Voting Agreement Parties.

Secondary Offering

On September 15, 2023, we consummated an underwritten registered secondary offering (the "Secondary Offering") of an aggregate of 8,165,000 shares of our common stock owned by GREP Holdco III-A, LLC and GREP Holdco III-B Holdings, LLC, each a Delaware limited liability company, at a price of $5.00 per share, pursuant to that certain Underwriting Agreement, dated September 12, 2023, among the Company, GREP Holdco III-A, LLC, GREP Holdco III-B Holdings, LLC, BofA Securities, Inc. and Evercore Group L.L.C. We did not sell any shares of our common stock in the Secondary Offering and did not receive any proceeds from the Secondary Offering.

Results of Operations

The following tables and related discussion set forth key operating and financial data as of and for the years ended December 31, 2023 and 2022. For similar operating and financial data and discussion of our 2022 results compared to our 2021 results, refer to "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" under Part II of our annual report on Form 10-K for the year ended December 31, 2022, which was filed with the SEC on March 27, 2023. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions and divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Year Ended December 31,	
	2023	2022
Net Sales (in thousands):		
Oil sales	$ 317,099	$ 338,163
Natural gas and related product sales	76,970	159,254
Revenues	394,069	497,417
Net Production:		
Oil (MBbl)	4,162	3,656
Natural gas (MMcf)	28,266	21,351
Total (MBoe)(1)	8,873	7,215
Average Daily Production:		
Oil (Bbl)	11,404	10,016
Natural gas (Mcf)	77,442	58,496
Total (Boe)(1)	24,311	19,765
Average Sales Prices:		
Oil (per Bbl)	$ 76.18	$ 92.50
Effect of gain (loss) on settled oil derivatives on average price (per Bbl)	1.10	(6.48)
Oil net of settled oil derivatives (per Bbl) (2)	77.28	86.02
Natural gas and related product sales (per Mcf)	2.72	7.46
Effect of gain (loss) on settled natural gas derivatives on average price (per Mcf)	0.65	(0.88)
Natural gas and related product sales net of settled natural gas derivatives (per Mcf) (2)	3.37	6.58
Realized price on a Boe basis excluding settled commodity derivatives	44.41	68.94
Effect of gain (loss) on settled commodity derivatives on average price (per Boe)	2.58	(5.88)
Realized price on a Boe basis including settled commodity derivatives (2)	46.99	63.06
Operating Expenses (in thousands):		
Lease operating expenses	$ 60,521	$ 44,678
Production and ad valorem taxes	27,707	30,619
Depletion and accretion expense	160,662	105,752
Impairments of long-lived assets	26,496	—
General and administrative	27,920	14,223
Costs and Expenses (per Boe):		
Lease operating expenses	$ 6.82	$ 6.19
Production and ad valorem taxes	$ 3.12	$ 4.24
Depletion and accretion	$ 18.11	$ 14.66
Impairments of long-lived assets	$ 2.99	$ —
General and administrative	$ 3.15	$ 1.97
Net Producing Wells at Period-End:	176.50	132.88

(1) Natural gas is converted to Boe using the ratio of one barrel of oil to six Mcf of natural gas.

(2) The presentation of realized prices including settled commodity derivatives is a result of including the net cash receipts from (payments on) commodity derivatives that are presented in our consolidated statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Oil, Natural Gas and Related Product Sales

Our revenues vary from year to year primarily due to changes in realized commodity prices and production volumes. In 2023, our oil and natural gas sales decreased 21% from 2022, driven by the decrease in realized prices, excluding the effect of settled commodity derivatives, partially offset by the increase in production. The lower average realized prices were driven by lower average NYMEX oil and natural gas prices.

Production from oil and gas properties increased because of drilling success and the acquisition of additional net revenue interests. This increase in production is offset by the natural decline of the production rate of existing oil and natural gas wells. The number of wells we participated in increased from 132.88 net wells in 2022 to 176.50 net wells in 2023.

The following table sets forth information regarding our oil and natural gas production by basin.

	Year Ended December 31,	
	2023	2022
Net Production:		
Oil (MBbl)		
Permian	2,656	2,347
Eagle Ford	529	467
Bakken	665	616
Haynesville	—	—
DJ	312	226
Total	4,162	3,656
Natural Gas (MMcf)		
Permian	9,146	5,957
Eagle Ford	3,055	2,001
Bakken	1,105	1,101
Haynesville	12,251	10,161
DJ	2,709	2,131
Total	28,266	21,351
Total (MBoe)		
Permian	4,180	3,339
Eagle Ford	1,038	801
Bakken	849	800
Haynesville	2,042	1,694
DJ	764	581
Total	8,873	7,215

Lease Operating Expenses

Lease operating expenses were $60.5 million ($6.82 per Boe) for the year ended December 31, 2023, an increase of 35% from $44.7 million ($6.19 per Boe) for 2022. The increase was primarily due to an increase in well count due to acquisitions and additional wells successfully drilled and completed, higher repair and maintenance costs and overall increased cost of services. The increase in lease operating expenses per Boe was primarily due to higher saltwater disposal costs, repair and maintenance costs and workover activity, partially offset by the increase in production.

Production and Ad Valorem Taxes

We generally pay production taxes based on realized oil and natural gas sales. Production taxes were $24.9 million ($2.81 per Boe) for the year ended December 31, 2023 compared to $26.9 million ($3.73 per Boe) for 2022. As a percentage of oil and natural gas sales, our production taxes were 6% and 5% in 2023 and 2022, respectively.

Production taxes generally fluctuate with the market value of our production sold, while ad valorem taxes are generally based on the valuation of our oil and natural gas properties at the beginning of the year, which vary across the different areas in which we operate.

Ad valorem taxes decreased during the year ended December 31, 2023 as compared to 2022, primarily due to additional wells drilled and completed and new wells acquired.

Depletion and Accretion

Depletion and accretion was $160.7 million ($18.11 per Boe) for the year ended December 31, 2023, an increase of 52% from $105.8 million ($14.66 per Boe) in 2022. The increase in depletion and accretion expense was primarily due to the increase in depletion expense resulting from the increase in production and depletion rate.

Impairment of long-lived assets

During the year ended December 31, 2023, we recognized impairment expense of $26.5 million. As a result of the decline in gas prices as well as reserve revisions in the Haynesville Basin, we compared the sum of the expected undiscounted future net cash flows to the carrying amount of the assets. As the carrying amount of the assets was higher than the expected undiscounted future net cash flows, an impairment loss was recorded as the difference between the carrying value and the estimated fair value.

General and Administrative

The following table provides components of our general and administrative expenses for the years ended December 31, 2023 and 2022:

	Year Ended December 31,	
(in thousands)	**2023**	**2022**
General and administrative expenses	$ 25,758	$ 14,223
Non-cash stock-based compensation	2,162	—
Total general and administrative expenses	$ 27,920	$ 14,223

Total general and administrative expenses were $27.9 million ($3.15 per Boe) for the year ended December 31, 2023, an increase of 96% from $14.2 million ($1.97 per Boe) in 2022. The increase was primarily due to $2.5 million of costs directly related to the Warrant Exchange, stock-based compensation of $2.2 million, annual compensation accruals related to the Company's officers and higher professional services and legal costs. The increase in stock-based compensation was due to the issuance of restricted stock awards, stock awards, stock options and PSUs. See Note 13 in the Notes to the Consolidated Financial Statements for additional information on stock-based compensation.

Gain/(Loss) on Derivatives – Commodity Derivatives

The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2023 and 2022:

	Year Ended December 31,	
(in thousands)	2023	2022
Gain (loss) on commodity derivatives		
Oil derivatives	$ 6,459	$ (14,985)
Natural gas derivatives	19,085	(10,339)
Total	$ 25,544	$ (25,324)

The following table represents our net cash receipts from (payments on) derivatives for the years ended December 31, 2023 and 2022:

	Year Ended December 31,	
(in thousands)	2023	2022
Net cash receipts from (payments on) commodity derivatives		
Oil derivatives	$ 4,576	$ (23,695)
Natural gas derivatives	18,319	(18,742)
Total	$ 22,895	$ (42,437)

Our earnings are affected by the changes in the value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains; while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Interest Expense

Interest expense was $5.3 million for the year ended December 31, 2023 compared to $2.0 million for 2022. The increase in interest expense was primarily due to the increase in interest rates and amortization of deferred financings costs, and higher average outstanding balance on the revolving credit facility.

Gain (Loss) on Derivatives – Common Stock Warrants

We recognized a loss of $5.7 million and a gain of $0.4 million during 2023 and 2022, respectively, from the change in fair value of the warrant liability. See Note 3 and Note 9 in the Notes to the Consolidated Financial Statements for additional information on the common stock warrants and the Warrant Exchange.

Income Tax Expense (Benefit)

We recorded an income tax expense of $24.5 million and $12.9 million in 2023 and 2022, respectively. The increase in income tax expense during the year ended December 31, 2023, compared with 2022, was due to the fact that the Funds were treated as partnerships for U.S. federal income tax purposes prior to the Business Combination and, as such, the partners of the Funds reported their share of the Fund's income or loss on their respective income tax returns for the applicable tax year (or portion thereof). In contrast, Granite Ridge is a corporation for U.S. federal income tax purposes and is subject to U.S. federal income taxes on any income or loss from the operation of the Company's assets following the Business Combination on October 24, 2022. The effective income tax rate differs from the statutory rate in 2023 primarily due to the impact of certain discrete items and state income taxes. The effective income tax rate differs from the statutory rate in 2022 primarily due to the allocation of profits and losses to the partners of the Funds for the period prior to the Business Combination. See Note 7 to the Notes to the Consolidated Financial Statements for additional discussion of income taxes.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources as of the periods covered by this report have been internally generated cash flow from operations and credit facility borrowings. Our primary use of capital has been for the development and acquisition of oil and natural gas properties. We continually monitor potential capital sources for opportunities to enhance liquidity or otherwise improve our financial position.

As of December 31, 2023, we had $110.0 million of debt outstanding under our Credit Agreement. We had $140.1 million of liquidity as of December 31, 2023, consisting of $129.7 million of committed borrowing availability under the Credit Agreement and $10.4 million of cash on hand. On November 7, 2023, Granite Ridge amended the Credit Agreement which, among other things, decreased the borrowing base from $325.0 million to $275.0 million and provided for aggregate elected commitments of $240.0 million, and amended the applicable margin charged on the loans and other obligations under the Credit Agreement. See Note 8 to the Notes to the Consolidated Financial Statements for additional information.

With our cash on hand, cash flow from operations, and borrowing capacity under the Credit Agreement, 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. We cannot assure you that any additional capital will be available to us on favorable terms or at all.

Capital commitments

Our recent capital commitments have been to fund the development and acquisition of oil and natural gas properties. We expect to fund our near-term capital requirements and working capital needs with cash on hand, cash flows from operations and available borrowing capacity under our Credit Agreement. Our capital expenditures could be curtailed if our cash flows decline from expected levels.

Common stock dividends

We paid dividends of $58.6 million, or $0.44 per share, and $10.7 million, or $0.08 per share during the years ended December 31, 2023 and 2022, respectively. On February 15, 2024, our Board of Directors declared a cash dividend of $0.11 per share for the first quarter of 2024 that will be paid on March 15, 2024 to stockholders of record as of March 1, 2024. Any payment of future dividends will be at the discretion of the Company's Board of Directors.

Stock repurchase program

In December 2022, we announced that our Board of Directors approved a stock repurchase program for up to $50.0 million of our common stock through December 31, 2023. The stock repurchase program terminated on December 31, 2023. As of December 31, 2023, the Company had repurchased a total of 5,677,627 shares since the inception of the program at an aggregate cost of $36.3 million.

Cash Flows

Our cash flows for the years ended December 31, 2023, 2022 and 2021 are presented below:

	Year Ended December 31,		
(in thousands)	**2023**	**2022**	**2021**
Net cash provided by operating activities	$ 302,867	$ 346,389	$ 181,181
Net cash used in investing activities	(356,676)	(230,562)	(186,024)
Net cash provided by (used in) financing activities	13,406	(76,848)	8,489
Net change in cash	$ (40,403)	$ 38,979	$ 3,646

Cash Flows from Operating Activities

The primary factors impacting our cash flows from operating activities generally include: (i) levels of production from our oil and natural gas properties, (ii) prices we receive from sales of oil and natural gas production, including settlement proceeds or payments related to our commodity derivatives, (iii) operating costs of our oil and natural gas properties, (iv) costs of our general and administrative activities and (v) interest expense. Our cash flows from operating activities have historically been impacted by fluctuations in oil and natural gas prices and our production volumes.

The $43.5 million decrease in operating cash flows during the year ended December 31, 2023 as compared to 2022 was primarily due to the decrease in oil and natural gas sales and higher operating costs, partially offset by $22.9 million of settlements received from commodity derivatives during 2023, as compared to $42.4 million of settlements paid on commodity derivatives during 2022.

Our net cash provided by operating activities included a benefit of $4.6 million and a reduction of $17.2 million for the years ended December 31, 2023 and 2022, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

Cash Flows from Investing Activities

For the year ended December 31, 2023, our net cash used in investing activities was $356.7 million, which consisted primarily of $282.4 million of capital expenditures for oil and natural gas properties and $76.8 million of acquisitions of oil and natural gas properties.

For the year ended December 31, 2022, our net cash used in investing activities was $230.6 million, which consisted primarily of $185.5 million of capital expenditures for oil and natural gas properties and $49.2 million of acquisitions of oil and natural gas properties.

Cash Flows from Financing Activities

For the year ended December 31, 2023, our net cash provided by financing activities was $13.4 million primarily due to $110.0 million of net borrowings under our Credit Agreement, partially offset by $58.6 million of dividends paid on our common stock and $35.4 million of common stock repurchases.

For the year ended December 31, 2022, our net cash used in financing activities was $76.8 million. We made net payments of $51.1 million on our credit facilities and paid $10.7 million of dividends during 2022. In addition, we paid $18.5 million of expenses related to the formation of Granite Ridge and $3.2 million of deferred financing cost related to the Credit Agreement. This was partially offset by the aggregate investment received by ENPC of $6.8 million in connection with the Business Combination, which represents total risk capital contributed by ENPC, including working capital loans that were forgiven.

Granite Ridge Credit Agreement

On October 24, 2022, the Funds terminated their revolving credit facilities, and we entered into the Credit Agreement among us, as borrower, Texas Capital Bank, as administrative agent, and the lenders from time to time party thereto. The Credit Agreement has a maturity of five years from the effective date thereof.

The Credit Agreement provided for aggregate elected commitments of $150.0 million, an initial borrowing base of $325.0 million and an aggregate maximum revolving credit amount of $1.0 billion. The borrowing base is scheduled to be redetermined semiannually on or about April 1 and October 1 of each calendar year, and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. On November 7, 2023, we entered into a First Amendment to the Credit Agreement (the "First Amendment") which, among other things, decreased the borrowing base from $325.0 million to $275.0 million and increased the aggregate elected commitments from $150.0 million to $240.0 million.

The Company and the Required Lenders (as defined in the Credit Agreement) may each request one unscheduled redetermination of the borrowing base between each scheduled redetermination. The amount of the borrowing base is determined by the lenders in their sole discretion and consistent with the oil and gas lending criteria of the lenders at the time of the relevant redetermination. The amount we are able to borrow under the Credit Agreement is subject to compliance with the financial covenants, satisfaction of various conditions precedent to borrowing and other provisions of the Credit Agreement.

At December 31, 2023, we had $110.0 million of outstanding debt and $0.3 million of letters of credit issued and outstanding under our Credit Agreement, resulting in committed borrowing availability of $129.7 million. The Credit

Agreement is guaranteed by our restricted subsidiaries and is secured by a first priority mortgage and security interest in substantially all of our assets and of our restricted subsidiaries.

Borrowings under the Credit Agreement may be base rate loans or secured overnight financing rate (“SOFR”) loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for SOFR loans. Prior to the effectiveness of the First Amendment, SOFR loans accrued interest at SOFR plus an applicable margin ranging from 250 to 350 basis points, depending on the percentage of the borrowing base utilized, plus an additional 10, 15 or 20 basis point credit spread adjustment for a one, three or six month interest period, respectively. Base rate loans accrued interest at a rate per annum equal to the greatest of: (i) the U.S. prime rate as published by the Wall Street Journal; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted SOFR rate for a one-month interest period plus 100 basis points, plus, in the case of this clause (iii), an additional 10 basis point credit spread adjustment, plus, in the case of any base rate loan, an applicable margin ranging from 150 to 250 basis points, depending on the percentage of the borrowing base utilized.

As a result of the First Amendment, SOFR loans now bear interest at SOFR plus an applicable margin ranging from 300 to 400 basis points, depending on the percentage of the borrowing base utilized, plus an additional 10, 15 or 20 basis point credit spread adjustment for a one, three or six month interest period, respectively. Base rate loans now bear interest at a rate per annum equal to the greatest of: (i) the U.S. prime rate as published by the Wall Street Journal; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted SOFR rate for a one-month interest period plus 100 basis points, plus, in the case of this clause (iii), an additional 10 basis point credit spread adjustment, plus, in the case of any base rate loan, an applicable margin ranging from 200 to 300 basis points, depending on the percentage of the borrowing base utilized.

We also pay a commitment fee on unused elected commitment amounts under our facility of 50 basis points. We may repay any amounts borrowed under the Credit Agreement prior to the maturity date without any premium or penalty.

The Credit Agreement also contains certain financial covenants, including the maintenance of the following financial ratios:

(i) a Current Ratio, (as defined in the Credit Agreement) of not less than 1.00 to 1.00 as of the last day of each fiscal quarter; and

(ii) a leverage ratio, which is the ratio of Consolidated Total Debt to EBITDAX (each as defined in the Credit Agreement), of not greater than 3.00 to 1.00 as of the last day of each fiscal quarter.

The Credit Agreement contains additional restrictive covenants that limit our ability and our restricted subsidiaries to, among other things, incur additional indebtedness, incur additional liens, enter into mergers and acquisitions, make or declare dividends, repurchase or redeem junior debt, make investments and loans, engage in transactions with affiliates, sell assets and enter into certain hedging transactions. In addition, the Credit Agreement is subject to customary events of default, including a change in control. If an event of default occurs and is continuing, the administrative agent may, with the consent of majority lenders, or shall, at the direction of the majority lenders, accelerate any amounts outstanding and terminate lender commitments.

As of December 31, 2023, we were in compliance with all covenants required by the Credit Agreement

Known Contractual and Other Obligations; Planned Capital Expenditures

Contractual and Other Obligations

- As of December 31, 2023, we had $110.0 million of debt outstanding under our Credit Agreement. See Note 8 of the Notes to the Consolidated Financial Statements for information regarding future interest payment obligations on our Credit Agreement.

- We entered into the MSA with the Manager in which we will pay the Manager an annual services fee of $10.0 million and will reimburse the Manager for certain Granite Ridge group costs related to the operation of our oil and gas assets and other properties. See Note 10 of the Notes to the Consolidated Financial Statements.

- We have contractual commitments that may require us to make payments upon future settlement of our commodity derivative contracts. See Note 3 of the Notes to the Consolidated Financial Statements.

- We have future obligations related to the abandonment of our oil and natural gas properties. See Note 6 of the Notes to the Consolidated Financial Statements.

- With respect to all of these items, except for our commitments under our debt agreements, we cannot determine with accuracy the amount and/or timing of such payments.

Planned Capital Expenditures

For 2024, we are budgeting approximately $265 million to $285 million in total planned capital expenditures, including approximately $35 million of acquisitions of oil and natural gas properties. We expect to fund planned capital expenditures with cash generated from operations and, if required, borrowings under our Credit Agreement.

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 above our acceptable levels, 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 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 changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, contractual obligations, internally generated cash flow, and other factors both within and outside our control.

Satisfaction of Our Cash Obligations for the Next Twelve Months

With our Credit Agreement and our positive cash flows from operations, we believe we will have sufficient capital to meet our drilling commitments, expected general and administrative expenses and other cash needs for the next twelve months. Nonetheless, any strategic acquisition of assets or increase in drilling activity may lead us to seek additional capital. We may also choose to seek additional capital rather than utilize our credit to fund accelerated or continued drilling at the discretion of management and depending on prevailing market conditions. We will evaluate any potential opportunities for acquisitions as they arise. However, there can be no assurance that any additional capital will be available to us on favorable terms or at all.

Effects of Inflation and Pricing

The oil and natural gas industry is typically very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. 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 current 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. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. Higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Critical Accounting Estimates

The establishment and consistent application of accounting policies is a vital component of accurately and fairly presenting our financial statements in accordance with generally accepted accounting principles in the United States (“U.S. GAAP”), as well as ensuring compliance with applicable laws and regulations governing financial reporting. While there are rarely alternative methods or rules from which to select in establishing accounting and financial reporting policies, proper application often involves significant judgment regarding a given set of facts and circumstances and a complex series of decisions. Further, these estimates and other factors, including those outside of management’s control could have significant adverse impact to the financial condition, results of operations and cash flows of the Company.

Use of Estimates

The preparation of financial statements under U.S. GAAP requires management to make estimates and assumptions that affect our reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period.

Oil and Natural Gas Reserves

The determination of depletion and amortization expense as well as impairments that are 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. As of December 31, 2023, approximately 42% of our total proved reserves were 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.

The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Such information includes revisions of certain reserve estimates attributable to the properties included in the prior year's estimates. These revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in oil and natural gas prices.

External petroleum engineers independently estimated all of the proved reserve quantities included in our financial statements, 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 provided them our historical information, such as oil and natural gas production, realized commodity prices, and operating and development costs. We also provided ownership interest information with respect to our properties. The third-party independent reserve engineers, NSAI, evaluated 100% of our estimated proved reserve quantities and their related pre-tax future net cash flows as of December 31, 2023.

Oil and Natural Gas Properties

Oil and natural gas producing activities are accounted for under the successful efforts method of accounting.

The successful efforts method inherently relies on the estimation of proved oil and natural gas reserves. The amount of estimated proved reserve volumes affect, among other things, whether certain costs are capitalized or expensed, the amount and timing of costs depleted into net income and the presentation of supplemental information on oil and gas producing activities. In addition, the expected future cash flows to be generated by producing properties used for testing impairment, also in part, rely on estimates of quantities of net reserves.

Depletion of oil and natural gas producing properties is determined using the units-of-production method. During the years ended December 31, 2023, 2022, and 2021, we recognized depletion expense of $160.2 million, $105.3 million and $94.2 million, respectively.

Any reduction in proved reserves could result in an acceleration of future depletion expense. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Holding all other factors constant, if proved reserves are revised downward, the rate at which we record depletion and accretion expense would increase, reducing net income. Conversely, if proved reserves are revised upward, the rate at which we record depletion and accretion expense would decrease. However, a sensitivity analysis is not practicable, given the numerous assumptions required to calculate proved reserves. In addition, any unfavorable adjustments to some of the above listed assumptions (e.g. commodity prices) would likely be offset by favorable adjustments in other assumptions (e.g. lower costs) as we have historically seen in our industry.

Impairment of Oil and Natural Gas Properties

All of our long-lived assets are monitored for potential impairment annually, or when circumstances indicate that the carrying value of an asset may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves, risk-adjusted probable and possible reserves, and integrated assets. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates, cash flows from integrated assets and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. At December 31, 2023, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2024 price of $71.68 per barrel of oil decreasing to a 2028 price of $62.02 per barrel of oil. Natural gas prices ranged from a 2024 price of $2.67 per Mcf of natural gas increasing to a 2028 price of $3.80 per Mcf. Both oil and natural gas commodity prices for this purpose were held flat after 2028. During the year ended December 31, 2023, we recognized an impairment expense of $26.5 million. We did not incur any impairment expense related to our proved oil and natural gas properties during the years ended December 31, 2022 or 2021.

Unproved oil and natural gas properties are assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. The Company did not recognize an impairment expense for the years ended December 31, 2023, 2022 and 2021 related to its unproved oil and natural gas properties.

Derivative Instruments – Commodity Derivatives

In order to reduce uncertainty around commodity prices received for our oil and natural gas operators' production, we enter into commodity price derivative contracts from time to time. We exercise significant judgment in determining the types of instruments to be used, the level of production volumes to include in our commodity derivative contracts, the prices at which we enter into commodity derivative contracts and the counterparties' creditworthiness.

We have not designated our derivative instruments as hedges for accounting purposes and, as a result, mark our derivative instruments to fair value and recognize the cash and non-cash change in fair value on derivative instruments for each period in the consolidated statements of operations. We are also required to recognize our derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation, and fair value is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions, including any deferred premiums, that are with the same counterparty and are subject to contractual terms which provide for net settlement. Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets. When the judgments used to estimate the initial fair value of the asset retirement obligation change, an adjustment is recorded to both the obligation and the carrying amount of the related long-lived asset. Historically, there have been no significant revisions to our initial estimates once future results became known. See Note 6 of the Notes to the Consolidated Financial Statements for additional information regarding our asset retirement obligations.

Revenue Recognition

The Company's revenues are derived from its interests in the sale of oil and natural gas production. As we do not operate any of our wells, we have limited visibility into the timing of when new wells start producing and production statements may not be received for one to three months or more after the date production is delivered. As a result, we are required to estimate the amount of production delivered to the purchaser and the price that we will receive for the sale of the product. Engineering estimates are typically used to calculate expected volumes. Pricing estimates are based upon actual prices realized in an area by adjusting the market price for the basis differential from market on a basin-by-basin basis. The expected sales volumes and prices for these properties are estimated and recorded within Revenue receivable line item in the accompanying consolidated balance sheets. Differences between our estimates and the actual amounts received for oil and natural gas sales are recorded in the month that payment is received from the third party.

Recently Issued or Adopted Accounting Pronouncements

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

Off-Balance Sheet Arrangements

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

Item 7A. ***Quantitative and Qualitative Disclosure about Market Risk***

Commodity Price Risk

We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on our earnings. For the year ended December 31, 2023, a 10% increase in average commodity prices would have decreased the fair value of commodity derivatives by $10.4 million. We may incur significant unrealized losses in the future from our use of derivative financial instruments to the extent market prices increase and our derivatives contracts remain in place.

We generally use derivatives to economically hedge a 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 Credit Agreement.

Interest Rate Risk

At December 31, 2023, our exposure to interest rate changes related primarily to the borrowings under the Credit Agreement. The interest we pay on these borrowings is set periodically based upon market rates. We had total indebtedness of $110.0 million outstanding under our Credit Agreement at December 31, 2023. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $1.1 million.

We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We had no outstanding interest rate derivative contracts at December 31, 2023.

Item 8. ***Financial Statements and Supplementary Data***

The financial statements and supplementary financial information required by this item are included on the pages immediately following the Index to Financial Statements appearing on page F-1.

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

None.

Item 9A. ***Controls and Procedures***

Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed in company reports filed or submitted under the Exchange Act is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2023, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2023, our disclosure controls and procedures were effective at a level of reasonable assurance.

Remediation of Previously Disclosed Material Weaknesses

As previously disclosed in Item 9A of our Annual Report on Form 10-K for the year ended December 31, 2022, management identified certain material weaknesses as of such date. The identified material weaknesses were in connection with the depletion calculation, accounting for acquisitions, and Information Technology General Controls ("ITGC") related to access to perform key duties within the financial systems. The material weaknesses related to the depletion calculation and accounting for acquisitions resulted in material errors that were corrected through a restatement of our previously filed unaudited condensed combined financial statements as of and for the three and nine month periods ended September 30, 2022.

In response to the material weaknesses referred to above, with the oversight of the Audit Committee of our Board of Directors, we implemented changes to our internal controls, which included the implementation of several controls related to reviews of the depletion calculation and acquisition accounting. Further, additional controls were implemented to address the ITGC material weakness to ensure only appropriate personnel have access to perform key duties within the financial systems. In addition, management added technical accounting personnel and leadership in January 2023, specifically in the form of a Chief Accounting Officer, to oversee and review accounting and financial reporting activities, as well as the establishment and implementation of internal control activities. Based on the evidence obtained in validating the design effectiveness of the implemented controls, we have concluded that the previously disclosed material weaknesses have been remediated as of December 31, 2023.

Changes in Internal Control over Financial Reporting

The changes described above under "Remediation of Previously Disclosed Material Weaknesses" represent a change in our internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) under the Exchange Act) 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 Annual Report on Internal Control Over Financial Reporting

The management of our Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the framework in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2013 Internal Control-Integrated Framework, management did not identify any material weaknesses in the Company's internal control over financial reporting and determined that the Company maintained effective internal control over financial reporting as of December 31, 2023.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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 Jumpstart Our Business Startups Act.

Inherent Limitations of Controls

Management does not expect that our disclosure controls and procedures or our internal control over financial reporting will prevent or detect all errors and all fraud. Controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of a simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or deterioration in the degree of compliance with the policies or procedures. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Item 9B. ***Other Information***

None.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

Not applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2023.

Item 11. ***Executive Compensation***

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement 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 and Related Stockholder Matters***

Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement 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***

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2023.

Item 14. ***Principal Accountant Fees and Services***

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2023.

Part IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a) The following consolidated financial statements are included in "Index to Financial Statements":

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2023 and 2022

Consolidated Statements of Operations for the Years Ended December 31, 2023, 2022 and 2021

Consolidated Statements of Cash Flows for the Years Ended December 31, 2023, 2022 and 2021

Consolidated Statements of Stockholders Equity for the Years Ended December 31, 2023, 2022 and 2021

Notes to the Consolidated Financial Statements

(b) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(c) Exhibits

Exhibit No.	Description
2.1	Business Combination Agreement, dated May 16, 2022, by and among Executive Network Partnering Corporation, Granite Ridge Resources, Inc., ENPC Merger Sub, Inc., GREP Merger Sub, LLC, and GREP (incorporated by reference to Annex A of Granite Ridge Resources, Inc.'s Registration Statement on Form S-4, filed with the SEC on May 16, 2022).

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Granite Ridge Resources, Inc. (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
3.2	Amended and Restated Bylaws of Granite Ridge Resources, Inc. (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
4.1	Description of Securities (incorporated by reference to Exhibit 4.1 to the Company's Annual Report on Form 10-K filed with the SEC on March 27, 2023).
4.2	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Granite Ridge Resources, Inc.'s Registration Statement on Form S-4/A, filed with the SEC on September 12, 2022).
4.3	Specimen Warrant Certificate (incorporated by reference to Exhibit 4.3 to Executive Network Partnering Corporation's Registration Statement on Form S-1, filed with the SEC on September 14, 2020).
4.4	Warrant Agreement, dated September 15, 2020 between Continental Stock Transfer & Trust Company and Executive Network Partnering Corporation (incorporated by reference to Exhibit 4.1 to Executive Network Partnering Corporation's Current Report on Form 8-K, filed with the SEC on September 21, 2020).
4.5	Amendment No. 1 to Warrant Agreement, dated March 24, 2021 between Continental Stock Transfer & Trust Company and Executive Network Partnering Corporation (incorporated by reference to Exhibit 1.01 to Executive Network Partnering Corporation's Current Report on Form 8-K, filed with the SEC on March, 25, 2021).
4.6	Assignment, Assumption and Amendment Agreement, dated October 24, 2022 by and among Executive Network Partnering Corporation, Granite Ridge Resources, Inc. and Continental Stock Transfer & Trust Company and Granite Ridge Resources, Inc. (incorporated by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.1	Registration Rights Agreement and Lock-Up Agreement, dated October 24, 2022 by and among Granite Ridge Resources, Inc., ENPC Holdings II, LLC and the other Holders (as defined therein) listed thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.2	Management Services Agreement, dated October 24, 2022 by and between Granite Ridge Resources, Inc. and Grey Rock Administration, LLC (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.3#	Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.4#	Form of Restricted Stock Award Agreement under the Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 11, 2023).
10.5#	Form of Performance Stock Unit Award Agreement under the Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 11, 2023).
10.6#	Form of Nonqualified Stock Option Award Agreement under the Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 11, 2023).
10.7	Credit Agreement, dated October 24, 2022 by and among Granite Ridge Resources, Inc., as borrower, Texas Capital Bank, as administrative agent and the lenders party thereto (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.7.1	First Amendment to Credit Agreement, dated as of November 7, 2023, by and among Granite Ridge Resources, Inc., as borrower, Texas Capital Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on November 9, 2023).
10.7.2*	Second Amendment to Credit Agreement, dated as of December 21, 2023, by and among Granite Ridge Resources, Inc., as borrower, Texas Capital Bank, as administrative agent, and the lenders party thereto.
10.8	Sponsor Agreement, dated as of May 16, 2022, by and among ENPC Holdings, LLC, ENPC Holdings II, LLC, Executive Network Partnering Corporation, Granite Ridge Resources, Inc., GREP Holdings, LLC and certain other parties thereto (incorporated by reference to Annex D of Granite Ridge Resources, Inc.'s Registration Statement on Form S-4, filed with the SEC on May 16, 2022).

Exhibit No.	Description
10.9	Form of Indemnity Agreement for Directors Affiliated with the Grey Rock funds (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.10	Form of Indemnity Agreement for Officers and Outside Directors (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.11#	Executive Employment Agreement between Luke C. Brandenberg and Granite Ridge Resources, Inc., dated October 24, 2022 (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.12#	Executive Employment Agreement between Tyler S. Farquharson and Granite Ridge Resources, Inc., dated October 24, 2022 (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of FORVIS, LLP, independent registered accounting firm of Granite Ridge Resources, Inc.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
97.1*	Granite Ridge Resources, Inc. Clawback Policy.
99.1*	Reserve Report of Granite Ridge Resources as of December 31, 2023.
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

* Filed herewith
\# Indicates management plan or compensatory arrangement.

Item 16. ***Form 10-K Summary***

None.

SIGNATURES

Pursuant to the requirements 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.

GRANITE RIDGE RESOURCES, INC.

March 8, 2024	By:	/s/ LUKE C. BRANDENBERG	
		Name:	Luke C. Brandenberg
		Title:	*President and Chief Executive Officer*
March 8, 2024	By:	/s/ TYLER S. FARQUHARSON	
		Name:	Tyler S. Farquharson
		Title:	*Chief Financial Officer*

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

Signature	Title	Date
/s/ Luke C. Brandenberg Luke C. Brandenberg	President and Chief Executive Officer (Principal Executive Officer)	March 8, 2024
/s/ Tyler S. Farquharson Tyler S. Farquharson	Chief Financial Officer (Principal Financial Officer)	March 8, 2024
/s/ Kimberly A. Weimer Kimberly A. Weimer	Chief Accounting Officer (Principal Accounting Officer)	March 8, 2024
/s/ Matt Miller Matt Miller	Director and Co-Chairman of the Board	March 8, 2024
/s/ Griffin Perry Griffin Perry	Director and Co-Chairman of the Board	March 8, 2024
/s/ Amanda N. Coussens Amanda N. Coussens	Director	March 8, 2024
/s/ Thaddeus Darden Thaddeus Darden	Director	March 8, 2024
/s/ Michele J. Everard Michele J. Everard	Director	March 8, 2024
/s/ Kirk Lazarine Kirk Lazarine	Director	March 8, 2024
/s/ John McCartney John McCartney	Director	March 8, 2024

Report of Independent Registered Public Accounting Firm

To the Shareholders, Board of Directors, and Audit Committee
Granite Ridge Resources Inc.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Granite Ridge Resources Inc. (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in equity, and cash flows for each of the years in the three-year period ended December 31, 2023, and the related notes (collectively referred to as the "financial statements"). In our opinion, the consolidated financial statements referred to above 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 cash flows for each of the years in the three-year period ended December 31, 2023, 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 include 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/ FORVIS, LLP

We have served as the Company's auditor since 2015.
Dallas, Texas
March 8, 2024

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

(in thousands, except par value and share data)	December 31, 2023	December 31, 2022
ASSETS		
Current assets:		
Cash	$ 10,430	$ 50,833
Revenue receivable	72,934	72,287
Advances to operators	4,928	8,908
Prepaid and other expenses	1,716	4,203
Derivative assets - commodity derivatives	11,117	10,089
Equity investments	50,427	—
Total current assets	151,552	146,320
Property and equipment:		
Oil and gas properties, successful efforts method	1,236,683	1,028,662
Accumulated depletion	(467,141)	(383,673)
Total property and equipment, net	769,542	644,989
Long-term assets:		
Derivative assets - commodity derivatives	1,189	—
Other long-term assets	4,821	3,468
Total long-term assets	6,010	3,468
Total assets	$ 927,104	$ 794,777
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accrued expenses	$ 60,875	$ 62,180
Other liabilities	1,204	1,523
Derivative liabilities - commodity derivatives	—	431
Total current liabilities	62,079	64,134
Long-term liabilities:		
Long-term debt	110,000	—
Derivative liabilities - common stock warrants	—	11,902
Asset retirement obligations	9,391	4,745
Deferred tax liability	73,989	49,749
Total long-term liabilities	193,380	66,396
Total liabilities	255,459	130,530
Commitments and contingencies (Note 11)		
Stockholders' Equity:		
Common stock, $0.0001 par value, 431,000,000 shares authorized, 136,040,777 and 133,294,897 issued at December 31, 2023 and 2022, respectively	14	13
Additional paid-in capital	653,174	632,075
Retained earnings	54,782	32,388
Treasury stock, at cost, 5,677,627 and 25,920 shares at December 31, 2023 and 2022, respectively	(36,325)	(229)
Total stockholders' equity	671,645	664,247
Total liabilities and stockholders' equity	$ 927,104	$ 794,777

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

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
(in thousands, except per share data)	2023	2022	2021
Revenues:			
Oil and natural gas sales	$ 394,069	$ 497,417	$ 290,193
Operating costs and expenses:			
Lease operating expenses	60,521	44,678	26,333
Production and ad valorem taxes	27,707	30,619	18,066
Depletion and accretion expense	160,662	105,752	94,661
Other	176	—	—
Impairments of long-lived assets	26,496	—	—
General and administrative (including non-cash stock-based compensation of $2,162 for the year ended December 31, 2023)	27,920	14,223	10,179
Gain on disposal of oil and natural gas properties	—	—	(2,279)
Total operating costs and expenses	303,482	195,272	146,960
Net operating income	90,587	302,145	143,233
Other income (expense):			
Gain (loss) on derivatives - commodity derivatives	25,544	(25,324)	(32,389)
Interest expense	(5,315)	(1,989)	(2,385)
Gain (loss) on derivatives - common stock warrants	(5,742)	362	—
Gain on equity investments	508	—	—
Total other income (expense)	14,995	(26,951)	(34,774)
Income before income taxes	105,582	275,194	108,459
Income tax expense	24,483	12,850	—
Net income	$ 81,099	$ 262,344	$ 108,459
Net income per share:			
Basic	$ 0.61	$ 1.97	$ 0.82
Diluted	$ 0.61	$ 1.97	$ 0.82
Weighted-average number of shares outstanding:			
Basic	133,093	132,923	132,923
Diluted	133,109	133,074	132,923

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

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(in thousands)	Previous Partnerships' Capital Existing Until the Recapitalization of Granite Ridge Resources, Inc.	Common Stock Issued		Additional Paid-in Capital	Retained Earnings	Treasury Stock		Total Equity
		Shares	Amount			Shares	Amount	
As of January 1, 2021	$ 370,556	—	$ —	$ —	$ —	—	$ —	$ 370,556
Cash distributions	(51,085)	—	—	—	—	—	—	(51,085)
Contributed capital	47,000	—	—	—	—	—	—	47,000
Carried interest reallocation	—	—	—	—	—	—	—	—
Net income	108,459	—	—	—	—	—	—	108,459
As of December 31, 2021	$ 474,930	—	$ —	$ —	$ —	—	$ —	$ 474,930
Net income prior to Business Combination	219,292	—	—	—	—	—	—	219,292
Contribution of Funds' assets in exchange for common stock	(694,222)	130,000	13	694,209	—	—	—	—
Recapitalization	—	2,923	—	6,825	—	—	—	6,825
Issuance costs	—	—	—	(18,508)	—	—	—	(18,508)
Issuance of common stock warrants	—	—	—	(12,265)	—	—	—	(12,265)
Issuance of vesting shares	—	372	—	(1,287)	—	—	—	(1,287)
Deferred income tax liability at Business Combination	—	—	—	(36,899)	—	—	—	(36,899)
Purchase of treasury stock	—	—	—	—	—	(26)	(229)	(229)
Common stock dividend declared ($0.08 per share)	—	—	—	—	(10,664)	—	—	(10,664)
Net income subsequent to the Business Combination	—	—	—	—	43,052	—	—	43,052
As of December 31, 2022	$ —	133,295	$ 13	$ 632,075	$ 32,388	(26)	$ (229)	$ 664,247
Adoption of ASU No. 2016-13 (Note 2)	—	—	—	—	(118)	—	—	(118)
As of January 1, 2023	$ —	133,295	$ 13	$ 632,075	$ 32,270	(26)	$ (229)	$ 664,129
Grants of restricted stock	—	403	—	—	—	—	—	—
Forfeitures of restricted stock	—	(13)	—	—	—	—	—	—
Cancellation of vesting shares	—	(221)	—	—	—	—	—	—
Vesting shares	—	—	—	1,287	—	—	—	1,287
Stock-based compensation	—	—	—	2,162	—	—	—	2,162
Purchase of treasury stock	—	—	—	—	—	(5,652)	(36,096)	(36,096)
Common stock dividend declared ($0.44 per share)	—	—	—	—	(58,587)	—	—	(58,587)
Common stock issued in warrant exchange	—	2,576	1	17,645	—	—	—	17,646
Common stock issued for exercise of warrants	—	1	—	5	—	—	—	5
Net income	—	—	—	—	81,099	—	—	81,099
As of December 31, 2023	$ —	136,041	$ 14	$ 653,174	$ 54,782	(5,678)	$ (36,325)	$ 671,645

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

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
(in thousands)	2023	2022	2021
Operating activities:			
Net income	$ 81,099	$ 262,344	$ 108,459
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion and accretion expense	160,662	105,752	94,661
Impairments of long-lived assets	26,496	—	—
(Gain) loss on derivatives - commodity derivatives	(25,544)	25,324	32,389
Net cash receipts from (payments on) commodity derivatives	22,895	(42,437)	(25,219)
Stock-based compensation	2,162	—	—
Gain on disposal of oil and gas properties	—	—	(2,279)
Amortization of loan origination costs	1,260	159	48
(Gain) loss on derivatives - common stock warrants	5,742	(362)	—
Gain on equity investments	(508)	—	—
Deferred income taxes	24,274	12,850	—
Other	(313)	—	—
Increase (decrease) in cash attributable to changes in operating assets and liabilities:			
Revenue receivable	(846)	(24,989)	(28,603)
Other receivable	103	—	—
Accrued expenses	4,550	9,838	1,840
Prepaid and other expenses	485	(2,095)	(125)
Other payable	350	5	10
Net cash provided by operating activities	302,867	346,389	181,181
Investing activities:			
Capital expenditures for oil and natural gas properties	(282,390)	(185,497)	(136,077)
Acquisition of oil and natural gas properties	(76,810)	(49,191)	(83,209)
Deposit on acquisition	—	(1,899)	—
Refund of advances to operators	2,464	1,180	3,819
Proceeds from the disposal of oil and natural gas properties	60	4,845	29,443
Net cash used in investing activities	(356,676)	(230,562)	(186,024)
Financing activities:			
Proceeds from borrowing on credit facilities	162,500	21,000	62,000
Repayments of borrowing on credit facilities	(52,500)	(72,100)	(49,400)
Cash distributions	—	—	(51,091)
Cash contributions	—	—	46,980
Deferred financing costs	(2,616)	(3,237)	—
Payment of expenses related to formation of Granite Ridge Resources, Inc.	(43)	(18,456)	—
Purchase of treasury shares	(35,353)	(216)	—
Payment of dividends	(58,587)	(10,664)	—
Proceeds from issuance of common stock	5	6,825	—
Net cash provided by (used in) financing activities	13,406	(76,848)	8,489
Net change in cash and restricted cash	(40,403)	38,979	3,646
Cash and restricted cash at beginning of year	51,133	12,154	8,508
Cash and restricted cash at end of year	$ 10,730	$ 51,133	$ 12,154
Supplemental disclosure of cash flow information:			
Cash paid during the year for interest	$ (4,825)	$ (2,286)	$ (1,636)
Cash paid during the year for income taxes	$ (742)	$ (98)	$ (79)
Supplemental disclosure of non-cash investing activities:			
Oil and natural gas properties divested in exchange for equity securities	$ 49,920	$ —	$ —
Oil and natural gas property development costs in accrued expenses	$ (12,325)	$ 48,187	$ 6,251
Advances to operators applied to development of oil and natural gas properties	$ 98,224	$ 103,535	$ 48,387
Cash and restricted cash:			
Cash	$ 10,430	$ 50,833	$ 11,854
Restricted cash included in other long-term assets	300	300	300
Cash and restricted cash	$ 10,730	$ 51,133	$ 12,154

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

GRANITE RIDGE RESOURCES, INC.
Notes to the Consolidated Financial Statements

1. Organization and nature of operations

Granite Ridge Resources, Inc. (together with its consolidated subsidiaries, "Granite Ridge" the "Company" or the "Successor") is a Delaware corporation, initially formed in May 2022, whose common stock is listed and traded on the New York Stock Exchange ("NYSE"). The Company was created for the purpose of the Business Combination (as defined below), and following the Business Combination, for the purpose of purchasing non-operated oil and natural gas assets in multiple basins in North America and realizing profits through participation in oil and natural gas wells.

On October 24, 2022, the Business Combination closed and was accounted for as a reverse recapitalization and Grey Rock Energy Fund III (as defined below) was determined to be the accounting acquirer and Predecessor (as defined below). Unless otherwise indicated, for the periods prior to October 24, 2022, (i) the historical financial data in this Annual Report on Form 10-K and (ii) the operating and other non-financial data, disclosed in "Part II – Management's Discussion and Analysis of Financial Condition and Results of Operations" (collectively the "Financial Statement Sections") reflect the combined business and operations of the Funds (as defined below).

Business Combination

On October 24, 2022 (the "Closing Date"), Granite Ridge and Executive Network Partnering Corporation, a Delaware corporation ("ENPC") consummated the Business Combination pursuant to the terms of the Business Combination Agreement, dated as of May 16, 2022 (the "Business Combination Agreement"), by and among ENPC, Granite Ridge, ENPC Merger Sub, Inc., a Delaware corporation and a wholly-owned subsidiary of Granite Ridge ("ENPC Merger Sub"), GREP Merger Sub, LLC, a Delaware limited liability company and a wholly-owned subsidiary of Granite Ridge ("GREP Merger Sub"), and Granite Ridge Holdings, LLC, a Delaware limited liability company formerly known as GREP Holdings, LLC ("GREP").

Pursuant to the Business Combination Agreement, on the Closing Date, (i) ENPC Merger Sub merged with and into ENPC (the "ENPC Merger"), with ENPC surviving the ENPC Merger as a wholly-owned subsidiary of Granite Ridge and (ii) GREP Merger Sub merged with and into GREP (the "GREP Merger," and together with the ENPC Merger, the "Mergers"), with GREP surviving the GREP Merger as a wholly-owned subsidiary of Granite Ridge (the transactions contemplated by the foregoing clauses (i) and (ii) the "Business Combination," and together with the other transactions contemplated by the Business Combination Agreement, the "Transactions").

Immediately prior to the closing of the Transactions, the net assets of Grey Rock Energy Fund, L.P., a Delaware limited partnership ("Fund I"), Grey Rock Energy Fund II, L.P., a Delaware limited partnership ("Fund II-A"), Grey Rock Energy Fund II-B, L.P., a Delaware limited partnership ("Fund II-B") and Grey Rock Energy Fund II-B Holdings, L.P., a Delaware limited partnership ("Fund II-B Holdings", and together with Fund II-A and Fund II-B, collectively, "Fund II"), and Grey Rock Energy Fund III-A, L.P., a Delaware limited partnership ("Fund III-A"), Grey Rock Energy Partners Fund III-B, L.P., a Delaware limited partnership ("Fund III-B"), and Grey Rock Energy Fund III-B Holdings, L.P., a Delaware limited partnership ("Fund III-B Holdings" and together with Fund III-A and Fund III-B, collectively, "Fund III" or "Predecessor") were transferred (through various intermediary entities) to GREP (the "GREP Formation Transaction"). Fund I, Fund II and Fund III are collectively referred to herein as, the "Funds".

At the special meeting of ENPC stockholders held in connection with the Business Combination, of the 41,400,000 shares of ENPC Class A common stock, public stockholders of 39,343,496 shares of ENPC Class A common stock exercised their rights to have those shares redeemed for cash at a redemption price of approximately $10.07 per share, or an aggregate of approximately $396.1 million. The holders of membership interests in GREP (the "Existing GREP Members") and their direct and indirect members were issued 130.0 million shares of Granite Ridge common stock at the closing. Upon consummation of the Business Combination, each public stockholder's ENPC common stock and ENPC warrants were automatically converted into an equivalent number of shares of Granite Ridge common stock and Granite Ridge warrants as a result of the Transactions. At the effective time of the Mergers, (i) 495,357 shares of ENPC Class F common stock were converted to 1,238,393 shares of ENPC Class A common stock (of which an aggregate of 220,348 shares were subsequently forfeited pursuant to the terms of the Sponsor Agreement) and the remaining shares of ENPC Class F common stock outstanding were automatically cancelled for no consideration (the "ENPC Class F Conversion") (ii) all other remaining shares of ENPC Class A common stock automatically cancelled without any conversion, payment or distribution (the "Sponsor Share Cancellation") and (iii) all shares of ENPC Class B common stock outstanding were deemed transferred to ENPC and surrendered and forfeited for no consideration (the "ENPC Class B Contribution"). In January 2023, 220,348 of the 371,518 shares subject to vesting and forfeiture provisions were forfeited.

Following the ENPC Class F Conversion, the Sponsor Share Cancellation, the ENPC Class B Contribution and the separation of the securities offered in ENPC's initial public offering, which consisted of one share of Class A common stock and one-quarter of one ENPC warrant ("CAPS™ Separation"), each share of ENPC Class A common stock outstanding was automatically converted into one share of Granite Ridge common stock. Total aggregate investment by ENPC was $6.8 million, which amount represents total risk capital contributed by ENPC, including working capital loans that were forgiven.

Fund III, Fund I and Fund II were identified as entities under common control, in which all entities are ultimately controlled by the same party before and after the GREP Formation Transaction and therefore resulted in a change in reporting entity. In accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 805-50-45-5, for transactions between entities under common control, the consolidated financial statements for periods prior to the GREP Formation Transaction have been adjusted to retrospectively combine the previously separate entities for presentation purposes.

Warrant Exchange

On October 24, 2022, in connection with the Business Combination, the Company issued 10,349,975 common stock warrants. On June 22, 2023, the Company completed an offer to holders of its outstanding warrants which provided such holders the opportunity to receive 0.25 shares of the Company's common stock in exchange for each warrant tendered by such holders (the "Offer"). This Offer coincided with a solicitation of consents from holders of the warrants to amend the warrant agreement governing such warrants to permit the Company to require that each warrant that remained outstanding upon the closing of the Offer be exchanged for 0.225 shares of the Company's common stock (together with the Offer, the "Warrant Exchange"). On June 22, 2023, the Company issued 2,471,738 shares of common stock in exchange for 9,887,035 warrants tendered in the Offer, with a minimal cash settlement in lieu of partial shares. In July 2023, each remaining outstanding warrant was converted into 0.225 shares of the Company's common stock, and subsequently, no warrants remained outstanding. See Note 9 for further discussion of the Warrant Exchange.

2. Summary of significant accounting policies

Principles of Consolidation

As it pertains to the periods prior to completion of the Business Combination, the financial statements have been presented on a combined historical basis due to the Funds' prior common ownership and control. Prior to the Business Combination, the financial statements include the accounts of the Funds, all of which were commonly owned and controlled. All inter-entity balances and transactions have been eliminated in combination.

As it pertains to the period subsequent to completion of the Business Combination, the accompanying consolidated financial statements also include the accounts of the Company, and all other wholly owned subsidiaries created in connection with the Business Combination. References to the "Company" prior to October 24, 2022 refer to the combined business of the Funds and references after October 24, 2022 refer to the consolidated business of Granite Ridge Resources, Inc.

Basis of Presentation

As a result of the Business Combination, periods prior to October 24, 2022 reflect Funds as limited partnerships, not as corporations. The primary financial impacts of the Transactions to the consolidated financial statements were (i) reclassification of partnership capital accounts to equity accounts reflective of a corporation and (ii) income tax effects. Since the Funds were identified as entities under common control, the consolidated financial statements for periods prior to the GREP Formation Transaction have been adjusted to retrospectively combine the previously separate entities for presentation purposes. All intercompany transactions within the consolidated businesses of the Company have been eliminated.

GRANITE RIDGE RESOURCES, INC.
Notes to the Consolidated Financial Statements

The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP"). The Company operates in one operating segment, which is oil and natural gas development, exploration and production. All of our operations are conducted in the geographic area of the United States. The Company's chief operating decision maker manages operations on a consolidated basis for purposes of evaluating operations and allocating resources.

Use of Estimates

The preparation of the consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates of reserves are used to determine depletion and to conduct impairment analysis. Estimating reserves is inherently uncertain, including the projection of future rates of production and the timing of development expenditures.

The Company's estimates of oil and natural gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and natural gas prices, future operating costs, severance taxes, development costs and work over costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves are later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity of the reserves, which could affect the carrying value of the Company's oil and natural gas properties and/or the rate of depletion related to the oil and natural gas properties.

Additional significant estimates include, but are not limited to, fair value of derivative financial instruments, fair value of equity investments, fair value of business combinations, asset retirement obligations, revenue receivable and income taxes. Actual results could differ from those estimates.

Reclassifications

Certain reclassifications have been made to prior years' reported amounts to conform to the current year presentation.

Prior Period Correction of an Immaterial Error

During the fourth quarter of 2023, the Company determined that the prior year consolidated financial statements had a misstatement caused by an error in determining the tax basis of oil and natural gas properties. Management concluded that the impact of this error on the prior year consolidated financial statements period is immaterial. However, given that the adjustment to correct the error in the current year consolidated financial statements would have a material impact on 2023, the Company has corrected the prior period consolidated financial statements in this Annual Report on Form 10-K in accordance with SEC guidance. The adjustment had no effect on the Company's net income, cash flows, total assets or total liabilities and stockholders' equity, and the information included in this Annual Report on Form 10-K sets forth the effects of this correction on the previously reported consolidated balance sheet as of December 31, 2022.

Due to transactions that were completed immediately prior to the Business Combination, the tax basis of oil and natural gas properties transferred to the Company was higher than initially recognized in 2022. As a result, the Company has corrected the deferred tax liability and additional paid-in capital in the accompanying consolidated balance sheet to properly reflect the increased tax basis upon the completion of the Business Combination. As shown below, the previously reported deferred tax liability as of December 31, 2022 has decreased and additional paid-in capital as of December 31, 2022 has increased. The following sets forth the effects of the correction on the previously reported consolidated balance sheet as of December 31, 2022:

(in thousands)	December 31, 2022
Deferred tax liability, previously reported	$ 91,592
Correction to deferred tax liability	(41,843)
Deferred tax liability, reported	$ 49,749

(in thousands)	December 31, 2022
Additional paid-in capital, previously reported	$ 590,232
Correction to additional paid-in capital	41,843
Additional paid-in capital, reported	$ 632,075

As a result of the change in the tax basis, the prior year standardized measure of discounted future net cash flows was corrected and increased by $30 million.

Cash and Restricted Cash

Cash represents liquid cash and investments with an original maturity of 90 days or less. The Company places its cash with reputable financial institutions. At times, the balances deposited may exceed amounts covered by insurance provided by the U.S. Federal Deposit Insurance Corporation (“FDIC”). However, management believes that the Company’s counterparty risks are minimal based on the reputation and history of the institutions selected. The Company has not incurred any losses related to amounts in excess of FDIC limits.

As of December 31, 2023 and 2022, the Company had $0.3 million of cash classified as restricted. This balance relates to a cash deposit for two standby letters of credit associated with oil and natural gas mining lease agreements. Restricted cash consists of cash that is stated at cost, which approximates fair market value. Classification of restricted cash is based on the nature of the restrictions associated with the underlying assets.

Revenue Receivable

Revenue receivable is comprised of accrued oil and natural gas sales. The operators remit payment for production directly to the Company. In the event of complete non-performance by the Company’s customers, the maximum exposure to the Company is the outstanding revenue receivable balance at the date of non-performance. The Company monitors this exposure primarily by reviewing credit ratings, financial statements and payment history. Revenue receivables are generally unsecured and typically received from the operator one to three months after production. The Company had an allowance for expected credit losses of $0.2 million at December 31, 2023 and $0.2 million at January 1, 2023, which was based on a historical loss rate. For the years ended December 31, 2022 and 2021, the Company’s bad debt expense and allowance for doubtful accounts was immaterial.

The Company considers forecasts of future economic conditions in the estimate of its expected credit losses, in particular whether there is an increase in the probability that the Company’s counterparties are unable to pay their obligations when due, and adjusts its allowance for expected credit losses, when necessary.

Advance to Operators

The Company participates in the drilling of oil and natural gas wells with other working interest partners. Due to the capital-intensive nature of oil and natural gas drilling activities, our partner operators may request advance payments from working interest partners for their share of the costs. The Company expects such advances to be applied by these operators against joint interest billings for its share of drilling operations within 90 days from when the advance is paid. Changes in advances to operators are presented as an investing outflow within capital expenditures for oil and gas properties on the statement of cash flows.

Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for oil and gas producing activities, as further defined under ASC 932, *Extractive Activities - Oil and Gas* ("ASC 932"). Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory leases that find proved reserves, and to drill and equip development leases and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determinations of whether the wells have proved reserves. If the Company determines that the wells do not have proved reserves, the costs are charged to expense. There were no exploratory wells capitalized pending determinations of whether the wells have proved reserves as of December 31, 2023 or 2022.

Capitalized leasehold costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized drilling and development costs and integrated assets is based on the unit-of-production method using proved developed reserves. The Company recognized depletion expense of $160.2 million, $105.3 million and $94.2 million for the years ended December 31, 2023, 2022, and 2021, respectively. As a result of the Business Combination, the Company aggregated certain proved properties for amortization and impairment purposes.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until the related project is completed. The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. For the year ended December 31, 2023, the Company capitalized $1.0 million of interest costs. For the years ended December 31, 2022 and 2021, no interest costs were capitalized. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

Effective January 1, 2019, the Company adopted ASU 2017-1, Business Combinations: Clarifying the Definition of Business ("ASU 2017-1"), with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. See discussions of the Company's oil and natural gas asset acquisitions and business combinations in Note 5. Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire depletion base is sold. However, gain or loss is recognized from the sale of less than an entire depletion base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. See Note 5 for additional information on our divestitures. Ordinary maintenance and repair costs are expensed as incurred.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair market value as determined by discounted future cash flows using a discount rate similar to that used by market participants, or comparable market value if available, is recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and risk-adjusted unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs and cash flows from integrated assets. The Company recorded proved property impairment of $26.5 million for the year ended December 31, 2023 related to its Haynesville properties. There were no proved property impairment indicators for the years ended December 31, 2022 or 2021.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. The Company did not recognize an impairment expense for the years ended December 31, 2023, 2022 and 2021 related to its unproved oil and natural gas properties.

Derivative Instruments- Commodity Derivatives

The Company recognizes its derivative instruments as either assets or liabilities measured at fair value. The Company nets the fair value of the derivative instruments by counterparty in the accompanying consolidated balance sheets when the right of offset exists. The Company does not have any derivatives designated as fair value or cash flow hedges.

Derivative Instruments- Common Stock Warrants

Prior to the Warrant Exchange, the Company accounted for warrants as liability-classified instruments based on an assessment of the warrant's specific terms and applicable authoritative guidance in Accounting Standards Codification ("ASC") Topic 480, "Distinguishing Liabilities from Equity" ("ASC 480") and ASC Topic 815, "Derivatives and Hedging" ("ASC 815"). The warrants were required to be recorded at their initial fair value on the date of issuance, and each balance sheet date thereafter. Changes in the estimated fair value of the warrants were recognized as a non-operating gain or loss on the consolidated statements of operations. For the period during which the Company's common stock was publicly traded, the fair value of the warrants was based on quoted prices in an active market. Refer to Note 4 for further discussion on fair value considerations.

On June 22, 2023, the Company issued 2,471,738 shares of common stock in exchange for 9,887,035 warrants tendered in the Offer, with a minimal cash settlement in lieu of partial shares. In July 2023, each remaining outstanding warrant was converted into 0.225 shares of the Company's common stock, and subsequently, no warrants remained outstanding. See Note 9 for further discussion of the Warrant Exchange.

Equity Investments

In December 2023, the Company completed the sale of certain of its Permian Basin assets to Vital Energy, Inc. ("Vital Energy") for consideration of 561,752 shares of Vital Energy's common stock and 541,155 shares of Vital Energy's 2.0% cumulative mandatorily convertible preferred securities. See Note 5 for further discussion of the divestiture of assets.

The Company follows the guidance in ASC 321, "Investments - Equity Securities" ("ASC 321") for its investment in the common and preferred stock of Vital Energy. ASC 321 requires equity investments with readily determinable fair values to be measured at fair value, with unrealized holding gains and losses recorded as a gain or loss on the consolidated statements of operations. For the preferred stock that does not have a readily determinable fair value, the Company has not elected the measurement alternative in ASC 321 and instead will account for the preferred stock at fair value with unrealized gains and losses recorded through net income. For the year ended December 31, 2023, an unrealized gain of $0.5 million on the change in fair value of the common and preferred stock is included in the consolidated statements of operations.

Asset Retirement Obligation

The Company follows the provisions of ASC 410-20, "Asset Retirement Obligations" ("ASC 410-20"). ASC 410-20 requires entities to record the fair value of obligations associated with the retirement of tangible long-lived assets in the period in which it is incurred. The Company's asset retirement obligation relates to the plugging, dismantlement, removal, site reclamation and similar activities of its oil and natural gas properties. When the liability is initially recorded, the entity capitalizes a cost by increasing the carrying amount of the related oil and natural gas property asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depleted over the useful life of the related asset. Based on certain factors, including commodity prices and costs, the Company may revise its previous estimates of the liability, which would also increase or decrease the related oil and natural gas property asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss for the difference of the settled amount and recorded liability.

Asset retirement obligations are estimated at the present value of expected future net cash flows and are discounted using the Company's credit adjusted risk free rate. The Company uses unobservable inputs in the estimation of asset retirement obligations that include, but are not limited to, costs of labor, costs of materials, profits on costs of labor and materials, the effect of inflation on estimated costs, and the discount rate. Due to the subjectivity of assumptions and the relatively long lives of the Company's leases, the costs to ultimately retire the Company's leases may vary significantly from prior estimates.

Revenue Recognition

The Company's revenues are primarily derived from its interests in the sale of oil and natural gas production. The Company recognizes revenue from its interests in the sales of oil and natural gas in the period that its performance obligations are satisfied.

Performance obligations are satisfied when the customer obtains control of product, when the Company has no further obligations to perform related to the sale, when the transaction price has been determined and when collectability is probable.

The Company receives payment from the sale of oil and natural gas production from one to three months after delivery. The transaction price is variable as it is based on market prices for oil and natural gas, less revenue deductions such as gathering, transportation and compression costs. Management has determined that the variable revenue constraint is overcome at the date control passes to the customer since the variable consideration to be received can be reasonably estimated based on daily market prices and historical transportation charges. Revenue is presented net of these costs within the consolidated statements of operations. At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are accrued in revenue receivable in the balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received; however, differences have been and are insignificant.

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in accordance with ASC 606. The expedient, as described in ASC 606-10-50-14(a), 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.

Non-operated Crude Oil and Natural Gas Revenues

The Company's proportionate share of production from non-operated properties is generally marketed at the discretion of the operators. For non-operated properties, the Company receives a net payment from the operator representing its proportionate share of sales proceeds which is net of transportation and production tax costs incurred by the operator, if any. Such non-operated revenues are recognized at the net amount of proceeds to be received by the Company during the month in which production occurs and it is probable the Company will collect the consideration it is entitled to receive. Proceeds are generally received by the Company within one to three months after the month in which production occurs.

Take-in Kind Oil and Natural Gas Revenues

Under certain arrangements, the Company has the right to take a volume of processed residue gas and/or natural gas liquids ("NGLs") in-kind at the tailgate of the midstream customer's processing plant in lieu of receiving a net payment from the operator representing its proportionate share of its natural gas production. The Company currently takes certain processed gas volumes in kind in lieu of monetary settlement but does not currently take NGL volumes. When the Company elects to take volumes in kind, it pays third parties to transport the processed products it took in-kind to downstream delivery points, where it then sells to customers at prices applicable to those downstream markets. In such situations, revenues are recognized during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Sales proceeds are generally received by the Company within one month after the month in which a sale has occurred. In these scenarios, gathering and processing costs and transportation expenses the Company incurs to transport the processed products to downstream customers are recorded in lease operating expenses on the consolidated statements of operations.

The Company's disaggregated revenue has two primary sources: oil sales and natural gas sales. Substantially all of the Company's oil and natural gas sales come from five geographic areas in the United States: the Eagle Ford Basin (Texas), the Permian Basin (Texas), the Haynesville Basin (Texas/Louisiana), the Denver-Julesburg "DJ" Basin (Colorado), and the Bakken Basin (Montana/North Dakota). The Company previously owned oil and natural gas assets in the SCOOP/STACK Basin in Oklahoma, which were sold during the year ended December 31, 2022. The following tables present the disaggregation of the Company’s oil revenues and natural gas revenues by basin for the years ended December 31, 2023, 2022 and 2021.

	Year Ended December 31,		
(in thousands)	2023	2022	2021
Oil	$ 317,099	$ 338,163	$ 215,250
Natural gas	76,970	159,254	74,943
Total	$ 394,069	$ 497,417	$ 290,193
Permian	$ 237,730	$ 266,856	$ 151,179
Eagle Ford	46,410	64,879	40,898
Bakken	51,128	64,999	56,055
Haynesville	24,833	62,743	12,039
DJ	33,968	37,880	29,191
SCOOP/STACK	—	60	831
Total	$ 394,069	$ 497,417	$ 290,193

Lease Operating Expenses

Lease operating expenses represents field employees’ salaries, saltwater disposal, repairs and maintenance, expensed workovers and other operating expenses. Lease operating expenses are expensed as incurred.

Production and Ad Valorem Taxes

The Company incurs production taxes on the sale of its production. These taxes are reported on a gross basis. Production taxes for the years ended December 31, 2023, 2022 and 2021 were approximately $24.9 million, $26.9 million and $17.1 million, respectively.

The Company incurs ad valorem tax on the value of its properties in certain states. Ad valorem taxes for the years ended December 31, 2023, 2022 and 2021 were approximately $2.8 million, $3.7 million and $1.0 million, respectively.

Income Taxes

Prior to the Business Combination, GREP and the associated activities held by the Funds were treated as partnerships for U.S. federal income tax purposes and were not subject to U.S. federal income tax. As a result of the Business Combination, the Company became a C corporation and is subject to U.S. federal income tax and state and local income taxes, and accounts for income taxes under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rate on deferred income tax assets and liabilities is recognized in income in the period that includes the enactment date.

A valuation allowance is provided for deferred income taxes if it is more likely than not these items will either expire before the Company is able to realize their benefits or if future deductibility is uncertain. Additionally, the Company evaluates tax positions under a more likely than not recognition threshold and measurement analysis before the positions are recognized for financial statement reporting. For further discussion, see Note 7.

Stock-Based Compensation

Stock-based compensation expense is recognized in the Company's consolidated financial statements on an accelerated basis over the awards' vesting periods based on their grant date fair values. Restricted stock awards are valued at the closing price of the Company's common stock on the date of grant. The Company utilizes the Monte Carlo simulation method to determine the fair value of certain performance stock units ("PSUs"), the Black-Scholes model for options issued at-the-money and a binomial lattice model for other stock options. The Company recognizes forfeitures on stock-based compensation awards as they occur.

Recently Issued and Applicable Accounting Pronouncements (Issued and Not Yet Adopted)

In June 2022, the FASB issued ASU No. 2022-03, "Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions," ("ASU 2022-03") which clarifies that a contractual restriction on the sale of an equity security is not considered part of the unit of account of the equity security and, therefore, is not considered in measuring fair value. ASU 2022-03 also clarifies that an entity cannot, as a separate unit of account, recognize and measure a contractual sale restriction and requires specific disclosures for equity securities subject to contractual sale restrictions such as the fair value of equity securities subject to contractual sale restrictions, the nature and remaining duration of the restrictions and the circumstances that could cause a lapse in the restriction. ASU 2022-03 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2023, with early application permitted. The Company does not expect the adoption of ASU 2022-03 to have a significant impact on its consolidated financial statements.

In November 2023, the FASB issued ASU No. 2023-07, "Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures," ("ASU 2023-07") which requires public entities, including public entities with a single reportable segment, to disclose significant segment expenses and other segment items on an annual and interim basis and to provide in interim periods all disclosures about a reportable segment's profit or loss and assets that are currently required annually. ASU 2023-07 is effective beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. Early adoption is permitted. The Company is currently assessing the effect that ASU 2023-07 will have on its disclosures.

In December 2023, the FASB issued ASU No. 2023-09, "Improvements to Income Tax Disclosures," ("ASU 2023-09") which requires disaggregated information about a reporting entity's effective tax rate reconciliation as well as information on income taxes paid. The standard is intended to benefit investors by providing more detailed income tax disclosures that would be useful in making capital allocation decisions. ASU 2023-09 is effective for annual periods beginning after December 15, 2024. Early adoption is permitted. The Company has not early adopted the standard and is currently assessing the effect that ASU 2023-09 will have on its disclosures.

Recently Issued and Applicable Accounting Pronouncements (Issued and Adopted)

The FASB issued ASU No. 2016-13, "Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" which replaced the "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. The adoption of this guidance on January 1, 2023 did not have a material impact on the Company's consolidated financial statements or related disclosures. Revenue receivables is the primary financial asset that is within the scope of the new guidance. A loss-rate method is applied to the receivables to estimate credit losses. The Company recognized a tax effected $0.1 million non-cash cumulative effect adjustment to retained earnings on its opening consolidated balance sheet at January 1, 2023 to record an allowance for expected credit losses associated with the Company's revenue receivables.

3. Derivative financial instruments

The Company uses derivative financial instruments in connection with its oil and natural gas operations to provide an economic hedge of the Company's exposure to commodity price risk associated with anticipated future oil and natural gas production. The Company does not hold or issue derivative financial instruments for trading purposes.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its consolidated statements of operations as they occur.

Collar Option Contracts and Swaps

The Company's derivative financial instruments consist of collar option contracts and swaps.

A collar option is established with the sale of a short call option (ceiling price) and the purchase of a long put option (floor price) set to expire at a predetermined date in the future. The options give the owner the right but not the obligation to exercise the option at the expiration date.

When the settlement price is below the established floor price, the Company receives an amount from its counterparty equal to the difference between the settlement price and the floor price multiplied by the hedged contract volume. When the settlement price is above the established ceiling price, the Company pays its counterparty an amount equal to the difference between the settlement price and the ceiling price multiplied by the hedged contract volume. When the settlement price is between the established floor and the ceiling, no amounts are due to or from the counterparty.

A swap contract allows the Company to receive a fixed price and pay a floating market price to the counterparty for the hedged commodity.

The Company has master netting agreements on individual derivative instruments with certain counterparties and therefore certain amounts may be presented on a net basis in the consolidated balance sheets.

Volume of Derivative Activities

The following table sets forth the Company's outstanding commodity derivative contracts as of December 31, 2023.

	2024					2025
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Total
Collar (oil)						
Volume (Bbl)	461,524	401,874	361,552	311,496	1,536,446	273,000
Weighted-average floor price ($/Bbl)	$ 64.22	$ 64.27	$ 64.32	$ 64.13	$ 64.24	$ 63.00
Weighted-average ceiling price ($/Bbl)	$ 84.99	$ 85.11	$ 85.24	$ 84.97	$ 85.07	$ 82.70
Swaps (oil)						
Volume (Bbl)	62,000	48,000	39,000	32,000	181,000	—
Weighted-average price ($/Bbl)	$ 80.00	$ 80.00	$ 80.00	$ 80.00	$ 80.00	$ —
Collar (natural gas)						
Volume (Mcf)	3,856,000	—	—	1,615,000	5,471,000	2,156,000
Weighted-average floor price ($/Mcf)	$ 2.93	$ —	$ —	$ 3.57	$ 3.12	$ 3.57
Weighted-average ceiling price ($/Mcf)	$ 4.39	$ —	$ —	$ 5.37	$ 4.68	$ 5.37
Swaps (natural gas)						
Volume (Mcf)	—	3,236,000	2,823,000	844,000	6,903,000	450,000
Weighted-average price ($/Mcf)	$ —	$ 3.22	$ 3.22	$ 3.22	$ 3.22	$ 3.68

The following table summarizes the amounts reported in the consolidated statements of operations related to the commodity derivative instruments for the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
(in thousands)	2023	2022	2021
Gain (loss) on commodity derivatives			
Oil derivatives	$ 6,459	$ (14,985)	$ (24,885)
Natural gas derivatives	19,085	(10,339)	(7,504)
Total	$ 25,544	$ (25,324)	$ (32,389)

The following table represents the Company's net cash receipts (payments on) commodity derivatives for the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
(in thousands)	2023	2022	2021
Net cash receipts from (payments on) commodity derivatives			
Oil derivatives	$ 4,576	$ (23,695)	$ (19,034)
Natural gas derivatives	18,319	(18,742)	(6,185)
Total	$ 22,895	$ (42,437)	$ (25,219)

Common stock warrants

On October 24, 2022, in connection with the Business Combination, the Company issued 10,349,975 common stock warrants. Each warrant entitled the holder to purchase one share of Granite Ridge's common stock at an exercise price of $11.50 per share. The common stock warrants became exercisable 30 days after the completion of the Business Combination and 461 common stock warrants were exercised as of December 31, 2023.

On June 22, 2023, the Company issued 2,471,738 shares of common stock in exchange for 9,887,035 warrants tendered in the Offer, with a minimal cash settlement in lieu of partial shares. In July 2023, each remaining outstanding warrant was converted into 0.225 shares of the Company's common stock.

The fair value of the common stock warrants as of December 31, 2022 was a liability of $11.9 million. The Company recognized a loss of $5.7 million and a gain of $0.4 million during 2023 and 2022, respectively, from the change in fair value of the warrant liability in the consolidated statements of operations. The warrants exchanged in the Offer were marked to fair value on the date of settlement, and the liability of $17.0 million and $0.7 million related to the exchanged common stock warrants was removed from the consolidated balance sheet in June 2023 and July 2023, respectively, and the issuance of shares of the Company's common stock was reflected in stockholders' equity. See Note 9 for further discussion of the Warrant Exchange.

4. Fair value measurements

The Company has adopted and follows ASC 820, *Fair Value Measurements and Disclosures*, for measurement and disclosures about fair value of its financial instruments. ASC 820 establishes a framework for measuring fair value in U.S. GAAP, and expands disclosures about fair value measurements. To increase consistency and comparability in fair value measurements and related disclosures, ASC 820 establishes a fair value hierarchy which prioritizes the inputs to valuation techniques used to measure fair value into three (3) broad levels. The fair value hierarchy gives the highest priority to quoted prices (unadjusted) in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. The three (3) levels of fair value hierarchy defined by ASC 820 are:

Level 1 — Inputs are unadjusted, quoted prices in active markets for identical assets or liabilities at the measurement date.

Level 2 — Inputs (other than quoted market prices included in Level 1) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level 3 — Inputs reflect management's best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model. Valuation of instruments includes unobservable inputs to the valuation methodology that are significant to the measurement of fair value of assets or liabilities.

As defined by ASC 820, the fair value of a financial instrument is the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced or liquidation sale, which was further clarified as the price that would be received to sell an asset or paid to transfer a liability ("an exit price") in an orderly transaction between market participants at the measurement date.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following table presents the carrying amounts and fair values of the Company's financial instruments as of December 31, 2023 and 2022:

	December 31, 2023		December 31, 2022	
(in thousands)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Assets:				
Derivative instruments - commodity derivatives	$ 12,306	$ 12,306	$ 10,089	$ 10,089
Equity investments	$ 50,427	$ 50,427	$ —	$ —
Liabilities:				
Derivative instruments - common stock warrants	$ —	$ —	$ 11,902	$ 11,902
Revolving credit facilities	$ 110,000	$ 110,000	$ —	$ —
Derivative instruments - commodity derivatives	$ —	$ —	$ 431	$ 431

Revolving credit facilities — The carrying amounts of the revolving credit facilities approximate their fair values, as the applicable interest rates are variable and reflective of market rates.

Other financial assets and liabilities — The carrying amounts of the Company's other financial assets and liabilities, such as revenue receivable and accrued expenses due to sellers, approximate their fair values because of the short maturity of these instruments.

Derivative instruments - commodity derivatives — The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. The fair value of the Company's commodity derivative instruments is considered to be a Level 2 measurement. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) current market and contractual prices for the underlying instruments, (iii) applicable credit-adjusted risk-free rate curves, as well as other relevant economic measures.

Derivative instruments - common stock warrants — The fair value of the Company's common stock warrant liability was valued using the instrument's publicly listed trading price, which is considered to be a Level 1 measurement due to the use of an observable market quote in an active market.

GRANITE RIDGE RESOURCES, INC.
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Equity investments — The fair value of the Company’s investment in Vital Energy's common stock was valued using the instrument's publicly listed trading price, which is considered to be a Level 1 measurement due to the use of an observable market quote in an active market. The fair value of the Company's investment in Vital Energy's preferred stock is estimated by management considering various factors, including the publicly listed trading price of Vital Energy's common shares and the present value of expected dividends prior to the conversion of the preferred shares. The fair value of the investment in preferred stock is considered to be a Level 2 measurement. Substantially all of these inputs are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

The Vital Energy common and preferred shares are subject to certain restrictions. Upon approval by holders of a majority of the issued and outstanding shares of Vital Energy common stock eligible to vote, the Preferred Stock is to be converted into common shares. Prior to this stockholder approval, the common shares owned by the Company are not entitled to vote and bear a restricted legend to that effect. For each share of Preferred Stock being converted, the Company shall receive a number of common shares in aggregate equal to the conversion rate. The initial conversion rate is one share of common stock per share of Preferred Stock. The conversion rate is adjusted upon the occurrence of events such as Vital Energy's issuance of common stock as a dividend, the issuance of common stock warrants or similar rights to all the common stockholders, the distribution of shares of its capital stock to acquire its capital stock or other securities, or if Vital Energy makes a cash distribution, except if it elects to give a dividend to the Preferred Stock in lieu of an adjustment to the conversion price.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following tables summarize (i) the valuation of each of the Company’s financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company’s consolidated balance sheets as of December 31, 2023 and 2022. The Company nets the fair value of commodity derivative instruments by counterparty in the Company’s consolidated balance sheets.

	Year Ended December 31, 2023					
	Fair Value Measurement Using					
(in thousands)	Level 1	Level 2	Level 3	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Equity investments - common stock	$ 25,554	$ —	$ —	$ 25,554	$ —	$ 25,554
Equity investments - preferred stock	—	24,873	—	24,873	—	24,873
Total equity investments	$ 25,554	$ 24,873	$ —	$ 50,427	$ —	$ 50,427
Assets (at fair value):						
Commodity derivatives – current portion	$ —	$ 14,202	$ —	$ 14,202	$ (3,085)	$ 11,117
Commodity derivatives – noncurrent portion	—	2,534	—	2,534	(1,345)	1,189
Liabilities (at fair value):						
Commodity derivatives – current portion	—	(3,085)	—	(3,085)	3,085	—
Commodity derivatives – noncurrent portion	—	(1,345)	—	(1,345)	1,345	—
Net derivative instruments	$ —	$ 12,306	$ —	$ 12,306	$ —	$ 12,306

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	Year Ended December 31, 2022					
	Fair Value Measurement Using					
(in thousands)	Level 1	Level 2	Level 3	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Assets (at fair value):						
Commodity derivatives – current portion	$ —	$ 20,197	$ —	$ 20,197	$ (10,108)	$ 10,089
Liabilities (at fair value):						
Commodity derivatives – current portion	—	(10,539)	—	(10,539)	10,108	(431)
Warrant liability – noncurrent portion	(11,902)	—	—	(11,902)	—	—
Net derivative instruments	$ (11,902)	$ 9,658	$ —	$ (2,244)	$ —	$ 9,658

Fair Values – Non Recurring

Impairments of long-lived assets — The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. The Company reviews its oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of the Company's assets, it recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

The Company calculates the expected undiscounted future net cash flows of its long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves, and (vii) prevailing market rates of income and expenses from integrated assets.

As of December 31, 2023, the Company's estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2024 price of $71.68 per barrel of oil decreasing to a 2028 price of $62.02 per barrel of oil. Natural gas prices ranged from a 2024 price of $2.67 per Mcf of natural gas increasing to a 2028 price of $3.80 per Mcf. Both oil and natural gas commodity prices for this purpose were held flat after 2028.

The Company calculates the estimated fair values of its long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows are generally discounted using an annual rate of 10 percent to determine fair value for proved developed producing reserves and an appropriate market discount rate based on risk for other reserve categories. These are classified as Level 3 fair value assumptions.

In the fourth quarter of 2023, there were indicators that the carrying value of the Company's Haynesville properties may be impaired due to a decline in natural gas prices and negative reserve revisions for certain wells that had recently begun production as well as certain proved undeveloped wells. As a result of the impairment evaluation, where the income approach was utilized (discounted cash flow model) to assess fair value, the Company recorded impairment of $26.5 million. The Company did not have any impairment indicators during the years ended December 31, 2022 or 2021. The following table presents the value of these assets measured at fair value on a nonrecurring basis at the time impairment was recorded:

	Year Ended December 31,					
	2023		2022		2021	
(in thousands)	Fair Value	Impairment	Fair Value	Impairment	Fair Value	Impairment
Oil and natural gas properties	$ 31,781	$ 26,496	$ —	$ —	$ —	$ —

Asset retirement obligations — The fair value measurements of asset retirement obligations are measured on a nonrecurring basis when a well is drilled or acquired or when production equipment and facilities are installed or acquired using a discounted cash flow model based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the fair value measurement of asset retirement obligations include estimates of the costs of plugging and abandoning oil and natural gas wells, removing production equipment and facilities and restoring the surface of the land as well as estimates of the economic lives of the oil and natural gas wells and future inflation rates.

5. Acquisitions and divestitures

The Company follows ASU 2017-1 in evaluating whether acquisitions of oil and natural gas properties are accounted for as asset acquisitions or as business combinations. The majority of the Company’s acquisitions during 2023, 2022 and 2021 qualified as asset acquisitions. Acquisitions that qualified as business combinations, as discussed below, were accounted for in accordance with ASC Topic 805, *Business Combinations*.

2023 Acquisitions

During 2023, the Company closed on three separate acquisitions that were treated as business combinations. These included the following transactions:

Multi-Basin Acquisition - In September 2023, the Company closed on an acquisition comprised of proved developed producing oil and natural gas properties with approximately 281 net acres. The properties are located in the Permian, Eagle Ford and DJ basins. As consideration for the acquisition, the Company paid $8.2 million in cash. Asset retirement obligations acquired were $0.2 million.

Haynesville Basin - In December 2023, the Company closed on an acquisition of proved and unproved oil and natural gas properties in the Haynesville Basin for $22.2 million in cash. Asset retirement obligations acquired were $0.2 million.

Haynesville Basin - In December 2023, the Company closed on an acquisition of royalty interests in proved and unproved oil and natural gas properties in the Haynesville Basin for $1.4 million in cash.

The following table presents a summary of the fair values of the assets acquired and the liabilities assumed in acquisitions that met the definition of a business combination:

(in thousands)	December 31, 2023
Fair value of assets acquired and liabilities assumed	
Proved oil and natural gas properties (1)	$ 15,488
Unproved properties	16,545
Total oil and natural gas properties	32,033
Less: Asset retirement obligations	(341)
Net assets acquired	$ 31,692
Consideration transferred (including liabilities assumed)	$ 31,692

(1) Amounts includes asset retirement costs of $0.3 million.

All other acquisitions during the year ended December 31, 2023 qualified as asset acquisitions. These included the following transactions:

Permian Basin - During the year ended December 31, 2023, the Company closed on various acquisitions of unproved oil and natural gas properties for a total purchase price of $24.3 million in the Permian Basin. The Company also closed on various acquisitions of proved oil and natural gas properties for a total purchase price of $0.3 million in the Permian Basin.

DJ Basin - During the year ended December 31, 2023, the Company closed on an acquisition of proved developed producing oil and natural gas properties in the DJ Basin. As consideration for the entire acquisition, the Company paid $16.6 million in cash, after closing adjustments, of which $1.9 million was held in escrow and paid during 2022. Asset retirement obligations acquired were $0.9 million.

Eagle Ford Basin - During the year ended December 31, 2023, the Company acquired proved oil and natural gas properties in the Eagle Ford Basin for $2.8 million.

Haynesville Basin - During the year ended December 31, 2023, the Company acquired various proved and unproved oil and natural gas properties in the Haynesville Basin for $2.9 million.

2023 Divestiture

In December 2023, the Company completed the sale of certain of its Permian Basin assets to Vital Energy in exchange for consideration of 561,752 shares of Vital Energy's common stock and 541,155 shares of Vital Energy's 2.0% cumulative mandatorily convertible preferred securities (the "Preferred Stock"). As the sale of oil and natural gas properties did not significantly affect the unit-of-production amortization rate of the Permian Basin depletion aggregation, the Company accounted for the divestiture as a normal retirement with no gain or loss recorded on the sale.

2022 Acquisitions

Bakken Basin – During the year ended December 31, 2022, the Company acquired proved oil and natural gas properties in the Bakken Basin for $1.6 million.

Permian Basin — During the year ended December 31, 2022, the Company closed on various asset acquisitions of unproved oil and natural gas properties for $18.0 million and proved oil and natural gas properties for $8.2 million in the Permian Basin.

During the year ended December 31, 2022, the Company completed an acquisition of proved and unproved oil and natural gas properties in the Permian Basin for $13.2 million. This acquisition met the definition of a business combination. The fair value allocated to proved and unproved oil and natural gas properties was $11.2 million and $2.0 million, respectively. Asset retirement obligations were immaterial.

DJ Basin — During the year ended December 31, 2022, the Company acquired unproved oil and natural gas properties in the DJ Basin for $2.9 million. In addition, the Company acquired proved oil and natural gas properties in the DJ Basin for $2.3 million.

Haynesville — During the year ended December 31, 2022, the Company acquired proved oil and natural gas properties in the Haynesville Basin for $3.0 million.

2022 Divestitures

Permian Basin - During the year ended December 31, 2022, the Company sold a partial unit of oil and natural gas properties in the Permian Basin for approximately $3.0 million, eliminating equivalent amounts from the oil and natural gas property accounts. No gain or loss was recorded.

Eagle Ford Basin — During the year ended December 31, 2022, the Company sold a partial unit of oil and natural gas properties in the Eagle Ford Basin for approximately $1.3 million, eliminating equivalent amounts from the oil and natural gas property accounts. No gain or loss was recorded.

2021 Acquisitions

Bakken Basin - During the year ended December 31, 2021, the Company acquired proved undeveloped oil and natural gas properties in the Bakken Basin of approximately $0.2 million.

Permian Basin – During the year ended December 31, 2021, the Company acquired various proved and unproved oil and natural gas properties in the Permian Basin of approximately $43.8 million.

DJ Basin - During the year ended December 31, 2021, the Company acquired various proved oil and natural gas properties of approximately $40.4 million. Customary post close adjustments were made during the year end December 31, 2022 which resulted in cash inflow of approximately $1.1 million.

2021 Divestitures

Bakken Basin - During the year ended December 31, 2021, the Company sold a partial unit of oil and natural gas properties in the Bakken Basin for $0.9 million recognizing the full amount as a gain.

Permian Basin - During the year ended December 31, 2021, the Company sold a complete unit of mineral interest assets in Texas for $22.5 million. The Company recorded a gain of $1.2 million associated with the sale. The Company also sold a partial unit of oil and natural gas properties in the Permian Basin for approximately $1.0 million, eliminating equivalent amounts from the property accounts.

SCOOP/STACK Basin - During the year ended December 31, 2021, the Company sold a complete unit of mineral interest assets in Oklahoma for approximately $1.9 million. The Company recorded a gain of $0.1 million associated with the sale.

Eagle Ford Basin- During the year ended December 31, 2021, the Company sold a partial unit of oil and natural gas properties in the Eagle Ford Basin for $3.0 million, eliminating equivalent amounts from the property accounts.

6. Asset retirement obligations

The Company recognizes the fair value of its asset retirement obligations related to the future costs of plugging, abandonment, and remediation of oil and natural gas producing properties at the times the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related oil and natural gas properties and allocated to expense over the useful life of the asset. Our asset retirement obligations primarily represent the present value of the estimated amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws.

The following table presents the changes in the asset retirement obligations during the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
(in thousands)	2023	2022	2021
Asset retirement obligations, beginning of year	$ 4,963	$ 2,962	$ 3,114
Liabilities incurred during the period	2,370	1,012	465
Revision of estimates (1)	2,596	490	(868)
Accretion of discount during the period	441	499	447
Disposals or settlements	(496)	—	(196)
Asset retirement obligations, end of year	$ 9,874	$ 4,963	$ 2,962
Less current portion of asset retirement obligations	483	218	—
Asset retirement obligations, long-term	$ 9,391	$ 4,745	$ 2,962

(1) Revisions in estimated liabilities during 2023 relate primarily to changes in estimated well lives, while revisions in prior year relate primarily to changes in estimates of asset retirement costs.

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7. Income taxes

In 2022, the Company became the sole owner of GREP. GREP is a disregarded entity for U.S. federal income tax purposes. Prior to the Business Combination, GREP and the associated activities held by the Funds were treated as partnerships for U.S. federal income tax purposes and were not subject to U.S. federal income tax. Any taxable income or loss generated prior to the Business Combination was passed through to and included in the taxable income or loss of its members. As a result of the Business Combination, the Funds' net assets were transferred to the Company resulting in carryover tax basis of those assets. The Company is a C corporation and subject to U.S. federal income tax and state and local income taxes. As described in Note 2, the Company corrected the previously reported deferred tax liability as of December 31, 2022.

The Components of income tax expense were as follows for the periods indicated:

(in thousands)	Year Ended December 31, 2023	2022	2021
Current			
Federal	$ —	$ —	$ —
State	209	—	—
	209	—	—
Deferred			
Federal	$ 22,314	$ 11,444	$ —
State	1,960	1,406	—
	24,274	12,850	—
Income tax expense	$ 24,483	$ 12,850	$ —

The Company's effective tax rate was 23.2%, 4.7% and 0.0% for years ended December 31, 2023, 2022 and 2021, respectively. For 2023, the effective tax rate differs from the enacted statutory rate of 21% primarily due to the impact of certain discrete items and state income taxes. For 2022, the effective tax rate differs from the enacted statutory rate of 21% primarily due to the allocations of profits and losses to ultimate members prior to the Business Combination and the impact of state income taxes.

The following reconciles the income tax expense included in the consolidated statements of operations with the income tax expense that would result from the application of the statutory federal tax rate:

(in thousands)	Year Ended December 31, 2023	2022	2021
Income (loss) before income taxes	$ 105,582	$ 275,194	$ 108,459
Income tax expense (benefit) at federal statutory rate	22,172	57,791	22,776
Net (income) loss prior to Business Combination - non taxable	—	(46,051)	(22,776)
Impact of prior tax returns	142	—	—
State income taxes, net of federal benefit	2,169	1,110	—
Income tax expense	$ 24,483	$ 12,850	$ —
Effective tax rate	23.2 %	4.7 %	0.0 %

Significant components of deferred tax assets and liabilities are included in the table below:

	Year Ended December 31,	
(in thousands)	2023	2022
Deferred tax assets		
Net operating loss carryforwards	$ 13,677	$ 11,500
Disallowed interest expense carryforward	1,335	56
Asset retirement obligation	2,169	1,128
Other deductible temporary differences	495	32
Total deferred tax assets	17,676	12,716
Less: valuation allowance	—	—
Net deferred tax assets	$ 17,676	$ 12,716
Deferred tax liabilities		
Property, plant and equipment	$ (88,870)	$ (60,269)
Unrealized derivatives	(2,795)	(2,196)
Total deferred tax liabilities	(91,665)	(62,465)
Net deferred tax liability	$ (73,989)	$ (49,749)

As of December 31, 2023, the Company had accumulated federal net operating loss carryforward of $61.1 million, none of which are expected to expire, and state net operating loss carryforwards of approximately $61.1 million in states that allow net operating loss carryforward, some of which begin to expire in 2042. Utilization of these net operating losses may be limited if there were to be an ownership change as defined by Section 382 of the U.S. Internal Revenue Code. As of December 31, 2023, the Company does not believe any of its net operating losses were limited under these rules.

The Company is subject to the various taxing jurisdictions in the United States, including federal and certain state jurisdictions. As of December 31, 2023, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes for tax years 2020 through 2023 and state income taxes for tax years 2019 through 2023.

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained upon examination. Therefore, as of December 31, 2023 and 2022, the Company had no unrecognized tax benefits and did not recognize any interest or penalties during those respective periods related to unrecognized tax benefits.

On August 16, 2022, the Inflation Reduction Act (the "IRA") was enacted into law and includes significant changes related to tax, climate change, energy and health care. The provisions within the IRA, among other things, include (i) a new 15% corporate alternative minimum tax on certain large corporations, (ii) a new nondeductible 1% excise tax on the value of certain stock that a company repurchases, and (iii) various tax incentives for energy and climate initiatives. Each of these provisions are effective for tax years beginning after December 31, 2022. The Department of the Treasury is expected to continue to publish regulations relevant to many aspects of the IRA. In addition to no 2023 impact on income tax expense, the Company currently does not believe that there will be a material impact on its cash taxes or income tax expense for the 2024 tax year or future periods but will continue to monitor.

8. Debt

The carrying value of the Company's total debt was $110.0 million at December 31, 2023. The Company had no debt outstanding at December 31, 2022.

Granite Ridge Credit Agreement

On October 24, 2022, Granite Ridge entered into a senior secured revolving credit agreement (as amended, the "Credit Agreement") among Granite Ridge, as borrower, Texas Capital Bank, as administrative agent, and the lenders from time to time party thereto. The Credit Agreement has a maturity date of five years from the effective date thereof.

The Credit Agreement initially provided for aggregate elected commitments of $150.0 million, an initial borrowing base of $325.0 million and an aggregate maximum revolving credit amount of $1.0 billion. The borrowing base is scheduled to be redetermined semiannually on or about April 1 and October 1 of each calendar year, and is subject to additional adjustments from time to time, including for asset sales, elimination or reduction of hedge positions and incurrence of other debt. On November 7, 2023, Granite Ridge entered into a First Amendment to the Credit Agreement (the "First Amendment") which, among other things, decreased the borrowing base from $325.0 million to $275.0 million and increased the aggregate elected commitments from $150.0 million to $240.0 million. This borrowing base decrease was a result of the disposition of certain assets in the Permian Basin to Vital Energy.

The Company and the Required Lenders (as defined in the Credit Agreement) may request one unscheduled redetermination of the borrowing base between each scheduled redetermination. The amount of the borrowing base is determined by the lenders in their sole discretion and consistent with the oil and gas lending criteria of the lenders at the time of the relevant redetermination. The amount Granite Ridge is able to borrow under the Credit Agreement is subject to compliance with the financial covenants, satisfaction of various conditions precedent to borrowing and other provisions of the Credit Agreement.

At December 31, 2023, the Company had outstanding borrowings of $110.0 million and $0.3 million of letters of credit issued and outstanding under the Credit Agreement, resulting in availability of $129.7 million. The Credit Agreement is guaranteed by the restricted subsidiaries of Granite Ridge and is secured by a first priority mortgage and security interest in substantially all of the Company's and its restricted subsidiaries' assets.

Borrowings under the Credit Agreement may be base rate loans or secured overnight financing rate ("SOFR") loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for SOFR loans. Prior to the First Amendment, SOFR loans accrued interest at SOFR plus an applicable margin ranging from 250 to 350 basis points, depending on the percentage of the borrowing base utilized, plus an additional 10, 15 or 20 basis point credit spread adjustment for a one, three or six month interest period, respectively. Base rate loans accrued interest at a rate per annum equal to the greatest of: (i) the U.S. prime rate as published by the Wall Street Journal; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted SOFR rate for a one-month interest period plus 100 basis points, plus, in the case of this clause (iii) an additional 10 basis point credit spread adjustment, plus, in the case of any base rate loan, an applicable margin ranging from 150 to 250 basis points, depending on the percentage of the borrowing base utilized.

As a result of the First Amendment, SOFR loans now bear interest at SOFR plus an applicable margin ranging from 300 to 400 basis points, depending on the percentage of the borrowing base utilized, plus an additional 10, 15 or 20 basis point credit spread adjustment for a one, three or six month interest period, respectively. Base rate loans now bear interest at a rate per annum equal to the greatest of: (i) the U.S. prime rate as published by the Wall Street Journal; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted SOFR rate for a one-month interest period plus 100 basis points, plus, in the case of this clause (iii) an additional 10 basis point credit spread adjustment, plus, in the case of any base rate loan, an applicable margin ranging from 200 to 300 basis points, depending on the percentage of the borrowing base utilized. The weighted average interest rate as of December 31, 2023 was 8.71%.

The Company also pays a commitment fee on unused elected commitment amounts under its facility of 50 basis points. The Company may repay any amounts borrowed under the Credit Agreement prior to the maturity date without any premium or penalty.

The Credit Agreement contains certain financial covenants, including the maintenance of the following financial ratios:

(i) a leverage ratio, which is the ratio of Consolidated Total Debt to EBITDAX (each as defined in the Credit Agreement), of not greater than 3.00 to 1.00 as of the last day of any fiscal quarter, and

(ii) a Current Ratio (as defined in the Credit Agreement), of not less than 1.00 to 1.00 as of the last day of each fiscal quarter.

At December 31, 2023, the Company was in compliance with all financial covenants required by the Credit Agreement.

9. Equity

As a result of the Business Combination, periods prior to October 24, 2022 reflect Granite Ridge as a limited partnership, not a corporation.

On the date of the Transactions, the capital of the Funds consisted of general partner interests and limited partner interests. The general partner interest was a non-economic, management interest. The general partner was granted full and complete power and authority to manage and conduct the business and affairs of the Funds and to take all such actions as it deemed necessary or appropriate to accomplish the purpose of the Funds. In connection with the Business Combination, the net assets of the Funds were transferred to GREP, which became a wholly-owned subsidiary of Granite Ridge. For additional information regarding the Business Combination, see Note 1.

Warrant Exchange - On June 22, 2023, the Company completed an Offer to holders of its outstanding warrants which provided such holders the opportunity to receive 0.25 shares of the Company's common stock in exchange for each warrant tendered by such holders. This Offer coincided with a solicitation of consents from holders of the warrants to amend the warrant agreement to permit the Company to require that each warrant that remained outstanding upon the closing of the Offer be exchanged for 0.225 shares of the Company's common stock. On June 22, 2023, the Company issued 2,471,738 shares of common stock in exchange for 9,887,035 warrants tendered in the Offer, with a minimal cash settlement in lieu of partial shares. In July 2023, each remaining outstanding warrant was converted into 0.225 shares of the Company's common stock, and subsequently, no warrants remained outstanding.

The warrants exchanged in the Offer were marked to fair value on the date of settlement, which was recorded in Gain (loss) on derivatives - common stock warrants on the consolidated statements of operations. Upon exchange, the liability of $17.0 million and $0.7 million related to the exchanged common stock warrants in June 2023 and July 2023, respectively, was removed from the consolidated balance sheet and the issuance of shares of the Company's common stock was reflected in stockholders' equity.

The Company incurred $2.5 million of costs directly related to the Warrant Exchange, consisting primarily of professional, legal, printing, filing, regulatory, and other costs. The costs were recorded in General and administrative expenses on the consolidated statements of operations for year ended December 31, 2023.

Common stock dividends - The Company paid dividends of $58.6 million, or $0.44 per share, and $10.7 million, or $0.08 per share during the years ended December 31, 2023 and 2022, respectively. Any payment of future dividends will be at the discretion of the Company's Board of Directors.

Share repurchase program - In December 2022, the Company announced that its Board of Directors approved a share repurchase program for up to $50.0 million. The stock repurchase program terminated on December 31, 2023.

During the years ended December 31, 2023 and 2022, the Company repurchased 5,651,707 and 25,920 shares under the program at an aggregate cost of $36.1 million and $0.2 million, respectively. As of December 31, 2023, the Company had repurchased a total of 5,677,627 shares since the inception of the program at an aggregate cost of $36.3 million.

Previous Capitalization

Prior to the Business Combination, the partners' capital attributable to the Funds was divided into two classifications: (1) General Partner and (2) Limited Partners. On the date of the Business Combination, the General Partner and Limited

Partner’s capital was exchanged for 130 million shares of common stock. See Note 1 for additional information on these and other transactions related to the Business Combination.

Vesting Shares

As discussed in Note 1, 495,357 shares of Class F common stock of ENPC were converted into 1,238,393 shares of Class A common stock of ENPC, 371,518 of which became subject to certain vesting and forfeiture provisions upon their conversion to the Company’s common stock in accordance with the Business Combination Agreement (the “Vesting Shares”). Based on an assessment of the Vesting Shares, the Company considered ASC 480 and accounted for the Vesting Shares as a liability. The Company recorded a liability related to the Vesting Shares of $1.3 million as of December 31, 2022. In January 2023, the Company reversed this liability and the related additional paid-in capital when 151,170 of these shares vested. The remaining shares were forfeited.

10. Related party transactions

On the Closing Date of the Business Combination, Grey Rock Administration, LLC (the “Manager”) entered into a Management Services Agreement with Granite Ridge (the “MSA”). Under the MSA, the Manager will provide general management, administrative and operating services covering the oil and gas assets and other properties of the Company and other day-to-day business and affairs of the Company. In accordance with the MSA, the Company shall pay the Manager an annual services fee of $10.0 million and shall reimburse the Manager for certain Granite Ridge group costs related to the operation of the Company’s assets (including for third party costs allocated or attributable to the Assets). The initial term of the MSA expires on April 30, 2028; however, the MSA will automatically renew for additional consecutive one-year renewal terms until terminated in accordance with its terms. Upon any termination of the MSA, the Manager shall provide transition services for a period of up to 90 days. For the years ended December 31, 2023 and 2022, service fees for the Company under the MSA were approximately $10.0 million and $1.9 million, respectively.

Prior to the Transaction, the Funds paid management fees to an investment advisor under common control with the Funds as compensation for providing managerial services to the Company.

For the periods ended December 31, 2022 and December 31, 2021, total management fees for the Company were $7.9 million and $6.2 million, respectively, and are included in general and administrative expenses within the accompanying consolidated statements of operations.

11. Commitments and contingencies

The Company is subject to various possible contingencies that arise primarily from interpretation of federal and state laws and regulations affecting the oil and gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Although management believes that it has complied with the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued. In addition, environmental matters are subject to regulation by various federal and state agencies.

On the Closing Date of the Business Combination, the Company entered into the MSA agreement between Granite Ridge and the Manager whereby the Company shall pay the Manager an annual services fee of $10.0 million and shall reimburse the Manager for certain Granite Ridge group costs. The initial term of the MSA expires on April 30, 2028; however, the MSA will automatically renew for additional consecutive one-year renewal terms until terminated in accordance with its terms.

12. Risk concentrations

As a non-operator, 100% of the Company’s wells are operated by third-party operating partners. As a result, the Company is highly dependent on the success of these third-party operators. If they are not successful in the development, exploitation, production and exploration activities relating to the Company’s leasehold interests, or are unable or unwilling to perform, the Company’s financial condition and results of operation could be adversely affected. These risks are heightened in a low commodity price environment, which may present significant challenges to these third-party operators. The Company’s third-party operators will make decisions in connection with their operations that may not be in the

Company's best interests, and the Company may have little or no ability to exercise influence over the operational decisions of its third-party operators.

The following table sets forth the percentage of revenues attributable to third-party operating partners who have accounted for 10% or more of revenues attributable to the Company's assets during the years ended December 31, 2023, 2022 and 2021.

Major Operators	2023	2022	2021
Operator A	11 %	12 %	12 %
Operator B	*	*	15 %
Operator C	12 %	10 %	*
Operator D	*	10 %	*

* Less than 10%

No other operator accounted for 10% or more of revenue attributable to the Company's assets on a combined basis in the years ended December 31, 2023, 2022, or 2021. The loss of any such operator could adversely affect revenues attributable to the Company's assets in the short term.

In the normal course of business, the Company maintains its cash balances in financial institutions, which at times may exceed federally insured limits. The Company is subject to credit risk to the extent any financial institution with which it conducts business is unable to fulfill contractual obligations on its behalf. Management monitors the financial condition of such financial institutions and does not anticipate any losses from these counterparties.

Derivative counterparties - The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. All of the Company's outstanding derivative instruments are covered by either International Swap Dealers Association Master Agreements ("ISDAs") entered into with parties that are also lenders under the Company's Credit Agreement or parties under the intercreditor agreement related to the Credit Agreement. The Company's obligation under the derivative instruments are secured pursuant to the Credit Agreement, and no additional collateral had been posted by the Company.

13. Stock Incentive Plan

In connection with the closing of the Transactions, the Company’s Board of Directors adopted the Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan (the “Plan”), which provides the Company the ability to grant, among other award types, stock options, restricted stock awards, and PSUs to directors, officers, employees and consultants or advisors employed by or providing service to the Company. The maximum number of shares of common stock that may be issued under the Plan is 6.5 million shares. The Company recognizes forfeitures on stock-based compensation awards as they occur.

During the first quarter of 2023, the Company granted restricted stock awards, fully vested stock awards, stock options, and PSUs. As of December 31, 2023, the Company had 5.7 million shares of common stock remaining available for future awards under the Plan. Shares issued as a result of awards granted under the Plan are generally new common shares.

The stock-based compensation expense and associated tax benefit were as follows:

(in thousands)		Year Ended December 31, 2023
Stock-based compensation expense		
Restricted Stock Awards	$	1,081
Performance Stock Units		47
Stock Options		234
Other Awards		800
Total stock-based compensation expense	$	2,162
Tax benefit recognized on compensation expense	$	311

Restricted Stock Awards - The Company has granted restricted stock awards to certain of its employees and consultants under the Plan. Restricted stock awards are valued at the closing price of the Company's common stock on the date of grant. All restricted shares are legally issued and outstanding. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and canceled and are no longer considered issued and outstanding. The holders of unvested restricted stock awards have voting rights and the right to receive dividends. The restricted stock awards generally vest ratably over a period of three years. The Company recognizes compensation expense utilizing graded vesting whereby compensation expense is recognized over the service period for each separately vesting tranche. A summary of the Company's restricted stock award activity for the year ended December 31, 2023 is presented below.

	Restricted Stock Awards		Weighted Average Grant Date Fair Value Per Share
Outstanding at December 31, 2022	—	$	—
Awards granted	308,938	$	5.72
Awards canceled/forfeited	(12,948)	$	5.01
Outstanding at December 31, 2023	295,990	$	5.75

PSUs - The Company has granted PSUs to certain of its officers under the Plan. The PSUs cliff vest at the end of a three-year performance period, generally subject to continued employment through the performance period. The total number of shares eligible to be earned may range from zero to 200% of the target number of PSUs granted, determined based upon achievement of certain “financial performance” and “market performance” criteria for the Company and individual performance criteria for the officers awarded PSUs. Financial performance is based on the Company’s financial performance at the end of the applicable performance period, while market performance is based on the relative standing of total shareholder return achieved by the Company compared to a predetermined group of peer companies at the end of the applicable performance period. Individual performance criteria is based on the officers’ performance relative to individual performance goals at the end of the performance period. The Company utilizes the Monte Carlo simulation method to determine the fair value of the PSUs. A summary of the Company's PSU activity for the year ended December 31, 2023 is presented below.

	Performance Stock Units	Weighted Average Grant Date Fair Value Per Share
Outstanding at December 31, 2022	—	$ —
Awards granted	26,574	$ 6.01
Outstanding at December 31, 2023	26,574	$ 6.01

Stock Options - The Company has granted stock options to certain of its officers under the Plan. The Company's outstanding stock options expire in 10 years following the date of grant. Pursuant to the stock options granted under the Plan, 33% of the options vested immediately with an additional 33% to vest on each of the next two anniversaries of the date of the grant, generally subject to continued employment through each such vesting date. Of the stock options granted during 2023, 72,108 of such stock options have an exercise price per share of $5.02, and 320,000 of the stock options have an exercise price per share of $9.22. A summary of the Company's stock option activity for the year ended December 31, 2023 is presented below.

	Stock Options	Weighted Average Exercise Price Per Share	Aggregate intrinsic value
			(in thousands)
Outstanding at December 31, 2022	—	$ —	
Options granted	392,108	$ 8.45	
Options canceled/forfeited	—	$ —	
Options exercised	—	$ —	
Outstanding at December 31, 2023	392,108	$ 8.45	$ 72
Options exercisable at December 31, 2023	130,702	$ 8.45	$ 24

The fair value of each stock option award was estimated on the date of grant. For stock options granted at-the-money (those with an exercise price of $5.02), grant date fair value was estimated using the Black-Scholes pricing model. As these options represent plain vanilla options and the Company did not have historical exercise detail, the expected term for these options was estimated using the simplified method allowed under Staff Accounting Bulletin Topic 14.D.2, which is the average of the weighted average vesting term and time to expiration as of the grant date. For stock options granted with an exercise price of $9.22, grant date fair value was estimated using a lattice-based option valuation model that incorporated a range of assumptions. Expected volatilities were based on historical volatilities of the Company's stock and other factors. The expected term was derived from the output of the option valuation model and represents the period of time that options granted are expected to be outstanding. The weighted average fair value of stock options on the date of the grant during the year ended December 31, 2023 was $0.82 per share. The weighted average remaining terms on the outstanding options and the exercisable options was 9.3 years. The Company used the following assumptions to estimate the fair value of stock options granted during the year ended December 31, 2023:

	Year Ended December 31, 2023
Risk-free interest rate	3.5% - 3.7%
Volatility	56.0% - 59.0%
Expected term	5.5 years - 7.8 years
Dividend yield	8.8%

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Stock Awards - During the first quarter of 2023, the Company issued 94,007 fully vested stock awards as other awards to certain of its employees and consultants under the Plan. Weighted average grant date fair value of other awards was $8.51.

Future stock-based compensation expense - The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at December 31, 2023:

(in thousands)	Restricted Stock Awards	Performance Stock Units	Stock Options
2024	$ 419	$ 62	$ 78
2025	174	62	12
2026	29	—	—
Total	$ 622	$ 124	$ 90

14. Earnings Per Share

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

The Company's basic earnings (loss) per share attributable to common stockholders is computed as (i) net income (loss) as reported, (ii) less participating basic earnings (iii) divided by weighted average basic common shares outstanding. The Company's diluted earnings (loss) per share attributable to common stockholders is computed as (i) basic earnings (loss) attributable to common stockholders, (ii) plus reallocation of participating earnings (iii) divided by weighted average diluted common shares outstanding.

The following table presents the basic and diluted earnings per share computations for the years ended December 31, 2023, 2022 and 2021:

	Year Ended December 31,		
(in thousands)	2023	2022	2021
Net income	$ 81,099	$ 262,344	$ 108,459
Participating basic earnings (a)	(152)	—	—
Basic earnings attributable to common stockholders	80,947	262,344	108,459
Reallocation of participating earnings	—	—	—
Diluted earnings attributable to common stockholders	$ 80,947	$ 262,344	$ 108,459
Weighted average common shares outstanding:			
Weighted average common shares outstanding – basic	133,093	132,923	132,923
Dilutive performance stock units	10	—	—
Dilutive stock options	6	—	—
Vesting Shares	0	151	0
Weighted average common shares outstanding – diluted	133,109	133,074	132,923
Net income (loss) per common share:			
Basic	$ 0.61	$ 1.97	$ 0.82
Diluted	$ 0.61	$ 1.97	$ 0.82

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with the common equity holders of the Company. Participating earnings represent the distributed and undistributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

Prior to the Warrant Exchange, the warrants were out-of-the-money and were not included in the computation of the diluted earnings per share. As a result of the Warrant Exchange, no warrants remained outstanding at December 31, 2023. Diluted weighted average common shares outstanding for the year ended December 31, 2022 included certain Vesting Shares, as defined in Note 9. Diluted net earnings per share for the year ended December 31, 2022 excluded 10,349,975 common stock warrants outstanding. There were no dilutive securities outstanding for the year ended December 31, 2021.

The following table is a summary of the PSUs and stock options, which were not included in the computation of diluted earnings per share, as inclusion of these items would be antidilutive.

	Year Ended December 31,		
	2023	2022	2021
Number of antidilutive common shares:			
Antidilutive performance stock units	23,428	—	—
Antidilutive stock options	303,805	—	—
Total antidilutive common shares	327,233	—	—

15. Accrued expenses

The following table provides the components of the Company’s accrued expenses at December 31, 2023 and December 31, 2022:

	December 31,	
(in thousands)	2023	2022
Accrued expenses:		
Accrued drilling costs	$ 32,739	$ 21,728
Accounts and JIB payable	20,037	32,216
Accrued production costs	5,729	6,710
Other	2,370	1,526
Total accrued expenses	60,875	62,180

16. Subsequent Events

On February 15, 2024, the Company's Board of Directors declared a cash dividend of $0.11 per share for the first quarter of 2024. The dividend will be paid on March 15, 2024 to stockholders of record as of March 1, 2024.

In February 2024, the Company entered into oil collars for the first half of 2025 for 166,852 Bbls with a floor price of $59.00 per Bbl and a ceiling price of $77.30 per Bbl. In addition, the Company entered into natural gas swaps for 1,162,050 Mcf for the second quarter of 2025 at a swap price of $3.02 per Mcf. The following table sets forth the Company’s outstanding commodity derivative contracts as of March 7, 2024.

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	2024					2025
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Total
Collar (oil)						
Volume (Bbl)	461,524	401,874	361,552	311,496	1,536,446	439,852
Weighted-average floor price ($/Bbl)	$ 64.22	$ 64.27	$ 64.32	$ 64.13	$ 64.24	$ 61.48
Weighted-average ceiling price ($/Bbl)	$ 84.99	$ 85.11	$ 85.24	$ 84.97	$ 85.07	$ 80.65
Swaps (oil)						
Volume (Bbl)	62,000	48,000	39,000	32,000	181,000	—
Weighted-average price ($/Bbl)	$ 80.00	$ 80.00	$ 80.00	$ 80.00	$ 80.00	$ —
Collar (natural gas)						
Volume (Mcf)	3,856,000	—	—	1,615,000	5,471,000	2,156,000
Weighted-average floor price ($/Mcf)	$ 2.93	$ —	$ —	$ 3.57	$ 3.12	$ 3.57
Weighted-average ceiling price ($/Mcf)	$ 4.39	$ —	$ —	$ 5.37	$ 4.68	$ 5.37
Swaps (natural gas)						
Volume (Mcf)	—	3,236,000	2,823,000	844,000	6,903,000	1,612,050
Weighted-average price ($/Mcf)	$ —	$ 3.22	$ 3.22	$ 3.22	$ 3.22	$ 3.20

Capitalized Costs

(in thousands)	December 31, 2023	December 31, 2022
Oil and natural gas properties:		
Proved	$ 1,198,845	$ 996,573
Unproved	37,838	32,089
Less: accumulated depletion	(467,141)	(383,673)
Net capitalized costs for oil and natural gas properties	$ 769,542	$ 644,989

Costs Incurred for Oil and Natural Gas Producing Activities

(in thousands)	December 31, 2023	2022	2021
Property acquisition costs:			
Proved	$ 36,824	$ 26,219	$ 42,569
Unproved	42,225	22,973	40,598
Development costs	283,915	256,664	103,918
Total costs incurred for oil and natural gas properties	$ 362,964	$ 305,856	$ 187,085

Oil and Natural Gas Reserves and Related Financial Data

Information with respect to the Company's oil and natural gas producing activities is presented in the following tables. Reserve quantities, as well as certain information regarding future production and discounted cash flows, were determined by independent third-party reserve engineers, based on information provided by the Company.

Prices presented in the table below are the trailing 12 month simple average spot price at the first of the month for natural gas at Henry Hub and West Texas Intermediate crude oil at Cushing, Oklahoma, prior to adjustments for location, grade and quality.

	December 31, 2023	2022	2021
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	$ 78.21	$ 94.14	$ 66.55
Natural gas per Mcf	2.64	6.36	3.60

The following tables present the Company's third-party independent reserve engineers estimates of its proved developed and undeveloped oil and natural gas reserves. The Company emphasized 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 the available data and of engineering and geological interpretation and judgment.

	Oil (MBbl)	Natural Gas (MMcf)	MBoe
Proved developed and undeveloped reserves at December 31, 2020	16,462	74,923	28,948
Revisions of previous estimates	651	18,964	3,814
Extensions and discoveries	2,543	9,420	4,113
Divestiture of reserves	(1,098)	(2,353)	(1,491)
Acquisition of reserves	7,673	39,254	14,216
Production	(3,413)	(14,861)	(5,890)
Proved developed and undeveloped reserves at December 31, 2021	22,818	125,347	43,710
Revisions of previous estimates	(456)	6,225	581
Extensions and discoveries	3,690	27,126	8,211
Divestiture of reserves	—	—	—
Acquisition of reserves	3,098	12,892	5,247
Production	(3,656)	(21,351)	(7,215)
Proved developed and undeveloped reserves at December 31, 2022	25,494	150,239	50,534
Revisions of previous estimates	(3,928)	(16,401)	(6,662)
Extensions and discoveries	7,150	35,798	13,116
Divestiture of reserves	(1,338)	(5,253)	(2,213)
Acquisition of reserves	4,101	20,811	7,570
Production	(4,162)	(28,266)	(8,873)
Proved developed and undeveloped reserves at December 31, 2023	27,317	156,928	53,472

	Oil (MBbl)	Natural Gas (MMcf)	MBoe
Proved developed reserves:			
December 31, 2020	10,053	36,585	16,150
December 31, 2021	11,658	54,257	20,702
December 31, 2022	15,714	91,034	30,886
December 31, 2023	14,972	96,833	31,111
Proved undeveloped reserves:			
December 31, 2020	6,409	38,338	12,798
December 31, 2021	11,160	71,090	23,008
December 31, 2022	9,780	59,205	19,648
December 31, 2023	12,345	60,095	22,361

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

- *Revisions of previous estimates.* In 2023, revisions of previous estimates decreased proved developed and undeveloped reserves by approximately 6,662 MBoe. The decrease was primarily driven by lower oil and natural gas prices. The Company's proved reserves at December 31, 2023 were determined using the SEC prices of $78.21 per Bbl of oil and $2.64 per MMBtu of natural gas, as compared to corresponding prices of $94.14 per Bbl of oil and $6.36 per MMBtu of natural gas at December 31, 2022. In addition to price revisions, there were negative revisions of 1,477 MBoe related to the removal of undeveloped drilling locations as they were no longer expected to be developed within five years of their initial recognition.

- *Extensions and discoveries.* In 2023, total extensions and discoveries of 13,116 MBoe were primarily attributable to successful drilling in the Permian Basin, which added 10,643 MBoe, and the Eagle Ford Basin, which added 1,835 MBoe. Proved developed reserves increased approximately 1,972 MBoe due to the Company's drilling activity in 2023, and 11,144 MBoe as a result of new proved undeveloped locations added.

- *Divestiture of reserves.* In 2023, the Company divested 2,213 MBoe of proved reserves in the Permian Basin (seee Note 5).

- *Acquisitions of reserves.* In 2023, total acquisitions of reserves of 7,570 MBoe were primarily attributable to the acquisitions of oil and natural gas properties in the Permian Basin and DJ Basin. The Permian Basin accounted for 5,342 MBoe of acquisitions and the DJ Basin accounted for 1,197 MBoe. See Note 5 for additional discussion regarding acquisitions.

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

- *Revisions of previous estimates.* In 2022, revisions of previous estimates increased proved developed and undeveloped reserves by approximately 581 MBoe. The increase was primarily driven by higher oil and natural gas prices. The Company's proved reserves at December 31, 2022 were determined using the SEC prices of $94.14 per Bbl of oil and $6.36 per MMBtu of natural gas, as compared to corresponding prices of $66.55 per Bbl of oil and $3.60 per MMBtu of natural gas at December 31, 2021. This increase was partially offset by negative revisions of 1,270 MBoe related to the removal of undeveloped drilling locations as they were no longer expected to be developed within five years of their initial recognition.

- *Extensions and discoveries.* In 2022, total extensions and discoveries of 8,211 MBoe were primarily attributable to successful drilling in the Permian and Eagle Ford Basins. Proved developed reserves increased approximately 699 MBoe due to the Company's drilling activity in 2022, and 7,512 MBoe as a result of new proved undeveloped locations added.

- *Acquisitions of reserves.* In 2022, total acquisitions of reserves of 5,247 MBoe were primarily attributable to the acquisitions of oil and natural gas properties in the Permian Basin (see Note 5).

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

- *Revisions of previous estimates.* In 2021, revisions of previous estimates increased proved developed and undeveloped reserves by a net amount of 3,814 MBoe. The upward revision in reserves was due to a combination of higher crude oil prices and favorable adjustments attributable to well performance, increasing reserves by 2,636 MBoe and 1,178 MBoe, respectively.

- *Extensions and discoveries.* In 2021, total extensions and discoveries of 4,113 MBoe were primarily attributable to successful drilling in the Bakken, Eagle Ford and Permian Basins as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 354 MBoe as a result of successful drilling in the Bakken, Eagle Ford and Permian Basins and 3,759 MBoe as a result of additional proved undeveloped locations.

- *Divestiture of reserves*. In 2021, divestiture of reserves of 1,491 MBoe were primarily attributable to the sale of oil and natural gas properties in the Permian Basin (see Note 5).

- *Acquisition of reserves.* In 2021, acquisition of reserves of 14,216 MBoe were primarily attributable to acquisitions of oil and natural gas properties in the Permian, Bakken and DJ Basins (see Note 5).

Proved reserves are estimated quantities of crude oil and natural gas, which geological and engineering data indicates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are proved reserved 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.

Standardized Measure of Discounted Future Net Cash Inflows and Changes Therein

Future oil and natural gas sales, production and development costs have been estimated using prices and costs in effect at the end of the years included, as required by ASC 932. ASC 932 requires that net cash flow amounts be discounted at 10%. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing our oil and natural gas reserves and for asset retirement obligations, assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate period-end statutory tax rates to the future pretax net cash flow relating to our proved oil and natural gas reserves, less the tax basis of the related properties and tax credits and loss carry forwards relating to crude oil and natural gas producing activities. The future income tax expenses do not give effect to tax credits, allowances, or the impact of general and administrative costs of ongoing operations relating to the Company's proved oil and natural gas reserves.

The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of reserves may not occur in the period assumed; actual prices realized are expected to vary significantly from those used and actual costs may vary.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved oil and natural gas reserves at 2023, 2022 and 2021:

	December 31,		
(in thousands)	2023	2022	2021
Future cash inflows	$ 2,589,302	$ 3,572,271	$ 2,007,425
Future production costs	(791,705)	(755,059)	(566,113)
Future development costs	(366,751)	(249,659)	(223,037)
Future income tax expense	(226,732)	(484,348)	(6,223)
Future net cash flows	1,204,114	2,083,205	1,212,052
10% discount for estimated timing of cash flows	(482,206)	(817,278)	(437,701)
Standardized measure of discounted future net cash flows	$ 721,908	$ 1,265,927	$ 774,351

A summary of the changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follow:

	December 31,		
(in thousands)	2023	2022	2021
Balance, beginning of period	$ 1,265,927	$ 774,351	$ 195,583
Sales of oil and natural gas produced, net of production costs	(305,843)	(422,120)	(245,794)
Extensions and discoveries	157,605	239,173	58,023
Previously estimated development cost incurred during the period	98,461	93,895	22,042
Net change of prices and production costs	(691,751)	671,556	332,625
Change in future development costs	6,284	(6,186)	(3,833)
Revisions of quantity and timing estimates	(204,963)	44,022	50,158
Accretion of discount	155,912	77,823	19,714
Change in income taxes	158,677	(289,317)	(2,315)
Acquisition of reserves	135,526	154,300	332,947
Divestiture of reserves	(77,402)	—	(13,589)
Other	23,475	(71,570)	28,790
Balance, end of period	$ 721,908	$ 1,265,927	$ 774,351

Second Amendment to Credit Agreement

This Second Amendment to Credit Agreement (this "Second Amendment"), dated as of December 21, 2023 (the "Second Amendment Effective Date"), is among Granite Ridge Resources, Inc., a Delaware corporation (the "Borrower"); each of the undersigned Restricted Subsidiaries of the Borrower (the "Guarantors"; the Guarantors together with the Borrower, the "Loan Parties"); each of the Lenders that is a signatory hereto; and Texas Capital Bank, as administrative agent for the Lenders (in such capacity, together with its successors in such capacity, the "Administrative Agent").

Recitals

A. The Borrower, the Administrative Agent, the Lenders and the L/C Issuer are parties to that certain Credit Agreement dated as of October 24, 2022 (as amended, restated, supplemented or otherwise modified prior to the date hereof, the "Credit Agreement"), pursuant to which the Lenders have, subject to the terms and conditions set forth therein, made certain credit available to and on behalf of the Borrower.

B. The Borrower has advised the Administrative Agent and the Lenders that Granite Ridge Holdings, LLC, a Delaware limited liability company, formerly known as GREP Holdings, LLC ("Holdings") has entered into that certain Purchase and Sale Agreement dated as of December 21, 2023 (as in effect on the date hereof and without giving effect to any subsequent amendment or modification thereto, the "Vital Sale Agreement"), among Holdings, GREP IV-A Permian LLC and GREP IV-B Permian LLC, collectively as "Sellers", and Vital Energy, Inc., a Delaware corporation, as "Buyer", pursuant to which Holdings will sell its applicable interest in the "Assets" (as defined in the Vital Sale Agreement) (the "Vital Disposition").

C. The parties hereto desire to enter into this Second Amendment to amend the Credit Agreement as set forth herein and effective as of the Second Amendment Effective Date.

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

Section 1. Defined Terms. Each capitalized term which is defined in the Credit Agreement, but which is not defined in this Second Amendment, shall have the meaning ascribed such term in the Credit Agreement, as amended hereby. Unless otherwise indicated, all section references in this Second Amendment refer to the Credit Agreement.

Section 2. Amendments. In reliance on the representations, warranties, covenants and agreements contained in this Second Amendment, and subject to the satisfaction of the conditions precedent set forth in Section 3 hereof, the Credit Agreement shall be amended, effective as of the Second Amendment Effective Date, in the manner provided in this Section 2.

1.1 Additional Definitions. Section 1.1 of the Credit Agreement is hereby amended to add thereto in alphabetical order the following definitions which shall read in their respective entireties as follows:

“Second Amendment” means that certain Second Amendment to Credit Agreement dated as of December 21, 2023, among the Borrower, the other Loan Parties party thereto, the Administrative Agent and the Lenders party thereto.

“Vital Assets” means the Oil and Gas Properties and other properties and interests collectively defined as “Assets” in the Vital Sale Agreement.

“Vital Disposition” means the Disposition by Granite Ridge Holdings, LLC, a Delaware limited liability company, formerly known as GREP Holdings, LLC and a Restricted Subsidiary of the Borrower of its applicable interest in the Vital Assets pursuant to the terms of the Vital Sale Agreement.

“Vital Sale Agreement” has the meaning assigned to such term in the Second Amendment.

1.2 Restated Definitions. The following definitions contained in Section 1.1 of the Credit Agreement are hereby amended and restated in their respective entireties to read in full as follows:

“Investment” means, for any Person: (a) the acquisition (whether for cash, Property, services or securities or otherwise) of Equity Interests of any other Person (including any “short sale” or any sale of any securities at a time when such securities are not owned by the Person entering into such short sale) or any contribution of capital to such Person; (b) the making of any deposit with, or advance or loan to, assumption of Debt of, purchase or other acquisition of any other Debt of, or other extension of credit to, any other Person (including any such transaction in the form of the purchase of Property from another Person subject to an understanding or agreement, contingent or otherwise, to resell such Property to such Person); (c) the purchase or acquisition (in one or a series of transactions) of Property (other than Equity Interests) of another Person that constitutes a business unit; or (d) the entering into of any guarantee of, or other surety obligation with respect to, any Debt of any other Person; *provided*, in each case that accounts receivable and extensions of credit (including extensions of credit to joint working interest owners) arising in the ordinary course of business do not constitute Investments. For the avoidance of doubt, the acquisition of certain Equity Interests in Vital Energy, Inc., a Delaware corporation by an Unrestricted Subsidiary of the Borrower on the effective date of the Vital Disposition in accordance with the Vital Sale Agreement will not constitute an “Investment” for the purposes of this Agreement or any other Loan Document.

“Loan Documents” means this Agreement, the First Amendment, the Second Amendment, the Guaranty, the Security Documents, the Notes, the Issuer Documents, each Fee Letter, the Hedge Intercreditor Agreement, and all other promissory notes, security agreements, intercreditor agreements, mortgages, deeds of trust, assignments, letters of credit, guaranties, and other instruments, documents, certificates and agreements executed and delivered pursuant to or in connection with this Agreement or the Security Documents; provided that the term “Loan Documents” shall not include any Secured Cash Management Agreement or any Secured Hedge Agreement; provided, further, that no Approved Swap Counterparty (in its capacity as such) shall be deemed to be a party or have any rights under any Loan Documents other than the Hedge Intercreditor Agreement to which it is a party.

1.3 Amendment to Section 2.8(g) of the Credit Agreement. Section 2.8(g) of the Credit Agreement is hereby amended by amending and restating clause (A) appearing therein to read in full as follows:

(A) the aggregate Borrowing Base value (as determined by Administrative Agent) of all Proved Oil and Gas Properties Disposed of by Borrower and its Restricted Subsidiaries (other than the Disposition of the Vital Assets, solely to the extent that the Vital Disposition occurs on or before February 29, 2024) occurring in any period between any two Redetermination Dates plus

1.4 Amendment to Section 8.8 of the Credit Agreement. Section 8.8 of the Credit Agreement is hereby amended by (i) deleting the reference to "and" at the end of clause (n) contained therein, (ii) deleting the reference to "." at the end of clause (o) contained therein and replacing such reference with "; and" and (iii) inserting a new clause (p) immediately following clause (o) contained therein which shall read in full as follows:

(p) the Vital Disposition, so long as such Disposition occurs on or before February 29, 2024.

Section 3. Conditions Precedent. The effectiveness of this Second Amendment is subject to the following:

1.1 Counterparts. The Administrative Agent shall have received counterparts of this Second Amendment from the Loan Parties and the Lenders constituting the Majority Lenders.

1.2 Fees. The Administrative Agent shall have received all fees and other amounts due and payable on or prior to the Second Amendment Effective Date.

1.3 Vital Sale Agreement. The Administrative Agent shall have received a certificate of a Responsible Officer of the Borrower certifying that attached to such certificate is a true, accurate and complete copy of the Vital Sale Agreement and any and all amendments thereto as of the Second Amendment Effective Date.

1.4 Other Documents. The Administrative Agent shall have received such other documents as the Administrative Agent or counsel to the Administrative Agent may reasonably request.

Section 4. Miscellaneous.

1.1 Confirmation and Effect. The provisions of the Credit Agreement (as amended by this Second Amendment) shall remain in full force and effect in accordance with their terms following the effectiveness of this Second Amendment, and the execution, delivery and effectiveness of this Second Amendment shall not (a) operate as a waiver of any right, power or remedy of any Lender, the L/C Issuer or the Administrative Agent under any of the Loan Documents nor (b) constitute a waiver of any provision of the Credit Agreement or any other Loan Document except, in each case, as expressly provided herein. Each reference in the Credit Agreement to "this Agreement", "hereunder", "hereof", "herein", or words of like import shall mean and be a reference to the Credit Agreement as amended hereby, and each reference to the Credit Agreement in any other document, instrument or agreement executed and/or delivered in connection with the Credit Agreement shall mean and be a reference to the Credit Agreement as amended hereby.

1.2 Ratification and Affirmation of Loan Parties. Each of the Loan Parties hereby expressly (a) acknowledges the terms of this Second Amendment, (b) ratifies and affirms its obligations under the Loan Documents to which it is a party, (c) acknowledges and renews its continued liability under the Loan Documents to which it is a party, (d) agrees, with respect to each Loan Party that is a Guarantor, that its guarantee under the Guaranty remains in full force and effect with respect to the Obligations as amended hereby, (e) represents and warrants to the Lenders and the Administrative Agent that each representation and warranty of such Loan Party contained in the Credit Agreement and the other Loan Documents to which it is a party is true and correct in all material respects as of the date hereof, after giving effect to the amendments set forth in Section 2 hereof, except (i) to the extent any such representations and warranties are expressly limited to an earlier date, in which case, on and as of the date hereof, such representations and warranties shall continue to be true and correct in all material respects as of such specified earlier date, and (ii) to the extent that any such representation and warranty is expressly qualified by materiality or by reference to Material Adverse Effect, such representation and warranty (as so qualified) shall continue to be true and correct in all respects, (f) represents and warrants to the Lenders and the Administrative Agent that the execution, delivery and performance by such Loan Party of this Second Amendment are within such Loan Party's corporate, limited partnership or limited liability company powers (as applicable), have been duly authorized by all necessary action and that this Second Amendment constitutes the valid and binding obligation of such Loan Party enforceable in accordance with its terms, except as the enforceability thereof may be limited by bankruptcy, insolvency or similar laws affecting creditor's rights generally, and (g) represents and warrants to the Lenders and the Administrative Agent that, immediately after giving effect to this Second Amendment, no Default exists.

1.3 Counterparts. This Second Amendment may be executed by one or more of the parties hereto in any number of separate counterparts, and all of such counterparts taken together shall be deemed to constitute one and the same instrument. Delivery of this Second Amendment by fax or electronic transmission (e.g. ".pdf") shall be effective as delivery of a manually executed original counterpart hereof. The execution and delivery of this Second Amendment shall be deemed to include electronic signatures on electronic platforms approved by the Administrative Agent, which shall be of the same legal effect, validity or enforceability as delivery of a manually executed signature, to the extent and as provided for in any applicable law, including the Federal Electronic Signatures in Global and National Commerce Act, the New York State Electronic Signatures and Records Act, or any other similar state laws based on the Uniform Electronic Transactions Act; *provided* that, upon the request of any party hereto, such electronic signature shall be promptly followed by the original thereof.

1.4 No Oral Agreement. This written Second Amendment, the Credit Agreement and the other Loan Documents executed in connection herewith and therewith represent the final agreement between the parties hereto or thereto and may not be contradicted by evidence of prior, contemporaneous, or unwritten oral agreements of the parties. There are no subsequent oral agreements between the parties that modify the agreements of the parties in the Credit Agreement and the other Loan Documents.

1.5 Governing Law. This Second Amendment (including, but not limited to, the validity and enforceability hereof) shall be governed by, and construed in accordance with, the laws of the State of Texas.

1.6 Payment of Expenses. The Borrower agrees to pay or reimburse the Administrative Agent for all of its reasonable out-of-pocket costs and expenses incurred in connection with this Second Amendment, any other documents prepared in connection herewith and the transactions contemplated hereby, including, without limitation, the reasonable fees and disbursements of counsel to the Administrative Agent.

1.7 Severability. Any provision of this Second Amendment which is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction.

1.8 Successors and Assigns. This Second Amendment shall be binding upon and inure to the benefit of the parties hereto and their respective successors and permitted assigns.

[Signature Pages Follow.]

The parties hereto have caused this Second Amendment to be duly executed as of the day and year first above written.

BORROWER: **GRANITE RIDGE RESOURCES, INC.**,
a Delaware corporation

By: /s/ Luke C. Brandenberg
Name: Luke C. Brandenberg
Title: President and Chief Executive Officer

GUARANTORS: **EXECUTIVE NETWORK PARTNERING CORPORATION,**
a Delaware corporation

By: /s/ Luke C. Brandenberg
Name: Luke C. Brandenberg
Title: President and Chief Executive Officer

GRANITE RIDGE HOLDINGS, LLC,
a Delaware limited liability company

By: /s/ Luke C. Brandenberg
Name: Luke C. Brandenberg
Title: President and Chief Executive Officer

TEXAS CAPITAL BANK,
as Administrative Agent and a Lender

By: /s/ Jared Mills
Name: Jared Mills
Title: Executive Director

BANK OF AMERICA, N.A.,
as a Lender

By: ___________

Name: ___________
Title: ___________

[Signature Page to Second Amendment to Credit Agreement
Granite Ridge Resources, LLC]

CAPITAL ONE NATIONAL ASSOCIATION,
as a Lender

By: /s/ David Lee Garza______

Name: David Lee Garza
Title: Vice President

PROSPERITY BANK,
as a Lender

By: /s/ Joe Kopidlansky______

Name: Joe Kopidlansky
Title: SVP – Corporate Banking

U.S. BANK NATIONAL ASSOCIATION,
as a Lender

By: /s/ Matthew A. Turner

Name: Matthew A. Turner
Title: Senior Vice President

FIRST-CITIZENS BANK & TRUST COMPANY,
as a Lender

By: ___________

Name: ___________
Title: ___________

[Signature Page to Second Amendment to Credit Agreement
Granite Ridge Resources, LLC]

Exhibit 21.1

Subsidiaries of the Registrant

The following list includes subsidiaries of Granite Ridge Resources, Inc. All subsidiaries are wholly-owned unless otherwise indicated.

Executive Network Partnering Corporation, a Delaware corporation

Granite Ridge Holdings, LLC, a Delaware limited liability company

Granite Ridge Reeves, LLC, a Delaware limited liability company

Granite Ridge Vital, LLC, a Delaware limited liability company

Exhibit 23.1

Consent of Independent Registered Accounting Firm

We consent to the incorporation by reference in the registration statements of Granite Ridge Resources, Inc. on Form S-1 Registration Statement (File No. 333-268478) and Form S-8 (File No. 333-269036) of our report, dated March 7, 2024, on our audits of the consolidated financial statements of Granite Ridge Resources, Inc. as of December 31, 2023 and 2022, and for each of the years in the three-year period ended December 31, 2023, which report is included in this Annual Report on Form 10-K.

/s/ FORVIS, LLP

FORVIS, LLP

Dallas, Texas
March 7, 2024

NETHERLAND, SEWELL & ASSOCIATES, INC.

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in the annual report on Form 10-K (the "Annual Report") of Granite Ridge Resources, Inc. (the "Company") of our report prepared for the Company dated January 16, 2024, with respect to estimates of reserves and future net revenue to the Company's interest, as of December 31, 2023, in certain oil and gas properties located in North Dakota, Texas, Louisiana, Montana, Wyoming, Colorado, and New Mexico. We also hereby consent to all references to our firm or such report included in or incorporated by reference into such Annual Report, and thus incorporated by reference into the Registration Statement on Form S-1 (File No. 333-268478) (including any amendments or supplements thereto, related appendices, and financial statements) and the Registration Statement on Form S-8 (File No. 333-269036) of Granite Ridge Resources, Inc.

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Eric J. Stevens
By:
Eric J. Stevens, P.E.
President and Chief Operating Officer

Dallas, Texas
March 8, 2024

Exhibit 31.1

CERTIFICATION

I, Luke C. Brandenberg, certify that:

1. I have reviewed this annual report on Form 10-K of Granite Ridge Resources, Inc.;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

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

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

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

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

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

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

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

Dated: March 8, 2024

By: /s/ LUKE C. BRANDENBERG
Luke C. Brandenberg
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Tyler S. Farquharson, certify that:

1. I have reviewed this annual report on Form 10-K of Granite Ridge Resources, Inc.;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

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

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

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

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

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

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

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

Dated: March 8, 2024	By: /s/ TYLER S. FARQUHARSON
	Tyler S. Farquharson
	Chief Financial Officer

Exhibit 32.1

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

In connection with the Annual Report of Granite Ridge Resources, Inc., (the "Company") on Form 10-K for the period ended December 31, 2023, as filed with the United States Securities and Exchange Commission on the date hereof, (the "Report"), the undersigned officers of the Company hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of their knowledge:

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

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company for the periods presented therein.

Dated: March 8, 2024	By:	/s/ LUKE C. BRANDENBERG	
		Name:	Luke C. Brandenberg
		Title:	*President and Chief Executive Officer*
Dated: March 8, 2024	By:	/s/ TYLER S. FARQUHARSON	
		Name:	Tyler S. Farquharson
		Title:	*Chief Financial Officer*

Exhibit 97.1

GRANITE RIDGE

Clawback Policy
Effective November 8, 2023

Purpose

As required pursuant to the listing standards of the New York Stock Exchange (the "Stock Exchange"), Section 10D of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and Rule 10D-1 under the Exchange Act, the Board of Directors (the "Board") of Granite Ridge Resources, Inc., a Delaware corporation (the "Company"), has adopted this Clawback Policy (the "Policy") to empower the Company to recover Covered Compensation (as defined below) erroneously awarded to a Covered Officer (as defined below) in the event of an Accounting Restatement (as defined below).

Notwithstanding anything in this Policy to the contrary, at all times, this Policy remains subject to interpretation and operation in accordance with the final rules and regulations promulgated by the U.S. Securities and Exchange Commission (the "SEC"), the final listing standards adopted by the Stock Exchange, and any applicable SEC or Stock Exchange guidance or interpretations issued from time to time regarding such Covered Compensation recovery requirements (collectively, the "Final Guidance"). Questions regarding this Policy should be directed to the Chairperson of the Compensation Committee of the Board.

Policy Statement

Unless a Clawback Exception (as defined below) applies, the Company will recover reasonably promptly from each Covered Officer the Covered Compensation Received (as defined below) by such Covered Officer in the event that the Company is required to prepare an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (each, an "Accounting Restatement"). If a Clawback Exception applies with respect to a Covered Officer, the Company may forgo such recovery under this Policy from any such Covered Officer.

Covered Officers

For purposes of this Policy, "Covered Officer" is defined as any current or former "Section 16 officer" of the Company within the meaning of Rule 16a-1(f) under the Exchange Act, as determined by the Board. Covered Officers include, at a minimum, "executive officers" as defined in Rule 3b-7 under the Exchange Act and identified under Item 401(b) of Regulation S-K.

Covered Compensation

For purposes of this Policy:

- "Covered Compensation" is defined as the amount of Incentive-Based Compensation (as defined below) Received during the applicable Recovery Period (as defined below) that exceeds the amount of Incentive-Based Compensation that otherwise would have been Received during such Recovery Period had it been determined based on the relevant restated amounts in the Accounting Restatement and computed without regard to any taxes paid.

Incentive-Based Compensation Received by a Covered Officer will only qualify as Covered Compensation if: (i) it is Received on or after October 2, 2023; (ii) it is Received after such Covered Officer begins service as a Covered Officer; (iii) such Covered Officer served as a Covered Officer at any time during the performance period for such Incentive-Based Compensation; and (iv) it is Received while the Company has a class of securities listed on a national securities exchange or a national securities association.

For Incentive-Based Compensation based on a measurement that is not subject to mathematical recalculation (including stock price or total shareholder return), the amount of such Incentive-Based Compensation that is deemed to be Covered Compensation will be based on the Board's reasonable estimate of the effect of the Accounting Restatement on the stock price or total shareholder return upon which the Incentive-Based Compensation was Received, and the Company will maintain and provide to the Stock Exchange documentation of the determination of such reasonable estimate.

- "Incentive-Based Compensation" is defined as any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure (as defined below). For purposes of clarity, Incentive-Based Compensation includes compensation that is in any plan, other than tax-qualified retirement plans, including long term disability, life insurance, and supplemental executive retirement plans, and any other compensation that is based on such Incentive-Based Compensation, such as earnings accrued on notional amounts of Incentive-Based Compensation contributed to such plans.

- "Financial Reporting Measure" is defined as a measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and any measures that are derived wholly or in part from such measures. Stock price and total shareholder return are also Financial Reporting Measures.

- Incentive-Based Compensation is deemed "Received" in the Company's fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that period.

Recovery Period

For purposes of this Policy, the applicable "Recovery Period" is defined as the three completed fiscal years immediately preceding the Trigger Date (as defined below) and, if applicable, any transition period resulting from a change in the Company's fiscal year within or immediately following those three completed fiscal years (provided, however, that if a transition period between the last day of the Company's previous fiscal year end and the first day of its new fiscal year comprises a period of nine to 12 months, such period would be deemed to be a completed fiscal year).

For purposes of this Policy, the "Trigger Date" as of which the Company is required to prepare an Accounting Restatement is the earlier to occur of: (i) the date that the Board, applicable Board committee, or officers authorized to take action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare the Accounting Restatement or (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare the Accounting Restatement.

Clawback Exceptions

The Company is required to recover all Covered Compensation Received by a Covered Officer in the event of an Accounting Restatement unless (i) one of the following conditions are met and (ii) the Compensation Committee of the Board (if then composed solely of independent directors) or a majority of the independent directors serving on the Board has made a determination that recovery would be impracticable in accordance with Rule 10D-1 under the Exchange Act (under such circumstances, a "Clawback Exception" applies):

- the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered (and the Company has already made a reasonable attempt to recover such erroneously awarded Covered Compensation from such Covered Officer, has documented such reasonable attempt(s) to recover, and has provided such documentation to the Stock Exchange);

- recovery would violate home country law that was adopted prior to November 28, 2022 (and the Company has already obtained an opinion of home country counsel, acceptable to the Stock Exchange, that recovery would result in such a violation, and provided such opinion to the Stock Exchange); or

- recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Internal Revenue Code and regulations thereunder. For purposes of clarity, this Clawback Exception only applies to tax-qualified retirement plans and does not apply to other plans, including long term disability, life insurance, and supplemental executive retirement plans, or any other compensation that is based on Incentive-Based Compensation in such plans, such as earnings accrued on notional amounts of Incentive-Based Compensation contributed to such plans.

Prohibitions

The Company is prohibited from paying or reimbursing the cost of insurance for, or indemnifying, any Covered Officer against the loss of erroneously awarded Covered Compensation.

Administration and Interpretation

The Board will administer this Policy in accordance with the Final Guidance, and will have full and exclusive authority and discretion to supplement, amend, repeal, interpret, terminate, construe, modify, replace and/or enforce (in whole or in part) this Policy, including the authority to correct any defect, supply any omission or reconcile any ambiguity, inconsistency or conflict in the Policy, subject to the Final Guidance. The provisions of the Final Guidance shall prevail in the event of any conflict between this Policy and the Final Guidance. The Board will review the Policy from time to time and will have full and exclusive authority to take any action it deems appropriate.

The Board will have the authority to offset any compensation or benefit amounts that become due to the applicable Covered Officers to the extent permissible under Section 409A of the Internal Revenue Code of 1986, as amended, and as it deems necessary or desirable to recover any Covered Compensation.

Each Covered Officer, upon being so designated or assuming such position, is required to execute and deliver to the Corporate Secretary of the Company an acknowledgment of and consent to this Policy, in the form attached to this Policy, (i) acknowledging and consenting to be bound by the terms of this Policy, (ii) agreeing to fully cooperate with the Company in connection with any of such Covered Officer's obligations to the Company pursuant to this Policy, and (iii) agreeing that the Company may enforce its rights under this Policy through any and all reasonable means permitted under applicable law as it deems necessary or desirable under this Policy.

Disclosure

This Policy, and any recovery of Covered Compensation by the Company pursuant to this Policy that is required to be disclosed in the Company's filings with the SEC, will be disclosed as required by the Securities Act of 1933, as amended, the Exchange Act, and related rules and regulations, including the Final Guidance.

GRANITE RIDGE

Clawback Policy Acknowledgment and Consent

The undersigned hereby acknowledges that he or she has received and reviewed a copy of the Clawback Policy (the "Policy") of Granite Ridge Resources, Inc., a Delaware corporation (the "Company"), effective as of November 8, 2023, as adopted by the Board of Directors of the Company.

Pursuant to such Policy, the undersigned hereby:

- acknowledges that he or she has been designated as (or assumed the position of) a Covered Officer (as defined in the Policy);
- acknowledges and consents to the Policy;
- acknowledges and consents to be bound by the terms of the Policy;
- agrees to fully cooperate with the Company in connection with any of the undersigned's obligations to the Company pursuant to the Policy, including, without limitation, the repayment by, or recovery from, the undersigned of Covered Compensation (as defined in the Policy); and
- agrees that the Company may enforce its rights under the Policy through any and all reasonable means permitted under applicable law as the Company deems necessary or desirable under the Policy.

ACKNOWLEDGED AND AGREED:

____
Name:_____________________________
Date:______________________________

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

January 16, 2024

Mr. Luke Brandenberg
Granite Ridge Resources, Inc.
5217 McKinney Avenue, Suite 400
Dallas, Texas 75205

Dear Mr. Brandenberg:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2023, to the Granite Ridge Resources, Inc. (Granite Ridge) interest in certain oil and gas properties located in the United States. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Granite Ridge. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Granite Ridge's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Granite Ridge interest in these properties, as of December 31, 2023, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	14,947.4	96,746.2	909,616.3	616,220.3
Proved Developed Non-Producing	25.0	86.8	1,658.3	1,218.1
Proved Undeveloped	12,344.8	60,094.8	519,571.9	238,989.6
Total Proved	27,317.3	156,927.8	1,430,846.6	856,427.8

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. As requested, probable and possible reserves that exist for these properties have not been included. The estimates of reserves and future revenue included herein have not been adjusted for risk. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated.

Gross revenue is Granite Ridge's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Granite Ridge's share of production taxes, ad valorem taxes, capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2023. For oil volumes, the average West Texas Intermediate spot price of $78.21 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.637 per MMBTU is adjusted for energy content, transportation fees, and market differentials; for certain properties, gas prices are negative after adjustments. When applicable, gas prices have been adjusted to include the value for natural gas liquids. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $75.96 per barrel of oil and $3.277 per MCF of gas.

Operating costs used in this report are based on operating expense records of Granite Ridge. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into per-well costs and per-unit-of-production costs. Since all properties are nonoperated, headquarters general and administrative overhead expenses are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Granite Ridge and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Granite Ridge's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Granite Ridge interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Granite Ridge receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Granite Ridge, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well location and acreage maps, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information

promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Granite Ridge, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. Nathan C. Shahan, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2007 and has over 5 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ Richard B. Talley, Jr.
By:
Richard B. Talley, Jr., P.E.
Chief Executive Officer

/s/ Nathan C. Shahan
By:
Nathan C. Shahan, P.E. 102389
Vice President

Date Signed: January 16, 2024

NCS:MBG

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is 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.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
(1) Lifting the oil and gas to the surface; and
(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;
(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

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

(i) The area of the reservoir considered as proved includes:

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

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

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Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are 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.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

e. Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.