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, 2024

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	**88-2227812**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
5217 McKinney Ave, Suite 400 Dallas, Texas	**75205**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (214) 396-2850

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

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 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, 2024, the last business day of the registrant’s most recently completed second fiscal quarter, was approximately $393,318,392 based on the $6.33 per share closing price of the registrant's common stock as reported on that day on the New York Stock Exchange.

As of March 3, 2025, there were 130,812,702 shares of the registrant's common stock outstanding.

Documents incorporated by reference: Portions of the definitive proxy statement related to the registrant's 2025 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," within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), 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, operating and financial performance, 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 Annual 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, 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 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; 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. 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.

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, workovers, 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 hydrocarbon 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.
- We may fail 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.
- 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.
- The payment of dividends is at the discretion of our Board of Directors, and we cannot assure you that we will continue making dividend payments in the future.

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, 2024

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 energy company which aims to provide shareholders with exposure similar to energy private equity through operated partnerships and traditional non-operated assets. We own assets in six prolific unconventional basins across the United States. We aim to deliver a diversified portfolio with best-in-class full cycle returns by investing in a large number of high-graded opportunities developed by proven public and private operators. We focus on success as measured by total shareholder returns, which we seek to balance with a low leverage profile.

To this end, we aim to:

- manage our current portfolio of assets to generate cash flow;
- participate in the development of new wells alongside operators with significant expertise in our core asset areas;
- source and evaluate new opportunities which provide healthy risk-adjusted returns; and
- return cash to shareholders as appropriate while maintaining a low leverage profile.

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 assets in the Permian (Delaware and Midland basins), Eagle Ford, Bakken, Haynesville, Denver-Julesburg ("DJ") and Appalachian basins (collectively, our "Properties"). The operators of our Properties include other public companies and experienced private companies. Operated partnerships are comprised of transactions where Granite Ridge makes controlled investments with proven teams in their area of expertise. Traditional non-operated assets are comprised of minority interests in core areas managed by experienced operators.

Operated Partnerships

We create operated partnerships by investing in assets which are drilled, developed and operated by private operators. We aim to partner with energy entrepreneurs who are experts within concentrated areas and back them with sufficient capital to develop a defined project. In these partnerships, we account for a significant majority of the capital at risk, so we have significant control over acquisition costs and strategy, development costs, timing and rig schedules, and well design. While it's unlikely that we would choose to do so, we also have a right to remove the operator of the position if need be and bring in a substitute operator for the asset. These partnerships resemble traditional energy private equity structures for the private operators as well as for Granite Ridge's investors. Typically, we structure these transactions to have an economic interest in the wells that benefits the operator after certain return hurdles are met to incentivize and align the operator with our interest.

Traditional Non-Operated Assets

Our non-operated asset base is built by investing in minority interests which give us a right to participate on a proportionate basis alongside third-party operators who propose, drill, and operate the assets. Once we own an asset in our portfolio, we assess each well proposal on a case-by-case basis to see if the well meets our return thresholds based upon our estimates of production from such well, capital expenditures, operating costs, expected oil and gas prices, operator expertise, as well as other factors. Our team uses an extensive proprietary data set to make these investment decisions. Given our acreage footprint and substantial number of well participations, we believe we can make reliably accurate decisions regarding the economics of participating in any proposed development project.

The following is a summary of information regarding our assets as of December 31, 2024, including reserves information as estimated by our third-party independent reserve engineers, Netherland, Sewell & Associates, Inc.

	As of December 31, 2024								
		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	15,065	714	64.70	—	—	13,191	37,232	56%	61%
Eagle Ford	6,587	129	27.40	100	7.30	3,495	4,835	58%	94%
Bakken	13,167	985	39.80	—	—	2,095	3,739	71%	99%
Haynesville	5,495	—	—	127	17.20	4,219	3,288	0%	92%
DJ	2,502	1,070	44.60	15	1.30	1,947	4,426	37%	93%
Appalachian	1,067	6	0.10	—	—	26	795	45%	86%
Total	43,883	2,904	176.60	242	25.80	24,973	54,315	52%	72%

Business Strategy

Key elements of our business strategy include:

Build a Diversified Portfolio: We invest in a large number of high-graded (typically directly sourced) opportunities which allow us to build a portfolio of 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) as well as operatorship. This diversification reduces the risk of our portfolio across commodity price cycles and idiosyncratic project-level risks.

Directly Source Accretive Opportunities: We are highly selective and focused only on investments that offer the best full cycle returns. We typically find higher risk-adjusted returns from aggregating multiple smaller transactions rather than 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. Historically, we have achieved higher returns by focusing on projects with near-term development rather than buying assets with a higher proportion of flowing production. We have a diverse range of opportunities, significantly reducing the risk associated with any single capital allocation decision. We allocate capital towards investments with compelling risk-reward balances and best-in-class full cycle returns.

Leverage Proprietary Data: As an owner in thousands of wells with dozens of operators across almost every core basin, we collect and analyze an immense amount of data. We invest in technology to drive accuracy and efficiency when evaluating opportunities, using our significant data set to gain unique insights for each transaction. Our robust technology capabilities allow for streamlined engineering processes, enabling our team to focus on value drivers to help us make effective and efficient investment decisions.

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. Subject to compliance with applicable law, and depending on, among other things, economic conditions, financial condition, results of operations, projections, liquidity, earnings, legal requirements, and restrictions in the Credit Agreement, we expect that Granite Ridge will pay quarterly cash dividends.

Mitigate Price Risk: We take a programmatic approach to commodity price risk management by hedging new drilling and acquisitions to protect near-term cash flow and provide through-cycle financial stability. While we cannot remove commodity price risk, we use a significant amount of hedging to help reduce that risk within a rolling 18 to 24-month period. 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.

Be a Good Partner: 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 off-market opportunities and mitigate risks inherent in the energy business.

Empower People: Our people are the lifeblood of our organization. We aim to encourage, support, and incentivize our team to develop and implement ideas that make us better.

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, 2024, 69% of our total proved reserves were located in the Permian Basin. During the year ended December 31, 2024, operators completed 133 gross (16.81 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, 2024, 9% of our total proved reserves were located in the Eagle Ford Basin. During the year ended December 31, 2024, operators completed 18 gross (3.36 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, 2024, 7% of our total proved reserves were located in the Bakken Basin. During the year ended December 31, 2024, operators completed 56 gross (1.00 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, 2024, 6% of our total proved reserves were located in the Haynesville Basin. During the year ended December 31, 2024, operators completed 6 gross (0.34 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, 2024, 8% of our total proved reserves were located in the DJ Basin. During the year ended December 31, 2024, operators completed 80 gross (1.78 net) wells in the DJ Basin.

Appalachian

The Appalachian Basin is a geologic basin in the eastern United States. Our acquisition and development efforts in this area are currently focused in the northern Utica Shale play within Ohio. At December 31, 2024, 1% of our total proved reserves were located in the Appalachian Basin. During the year ended December 31, 2024, operators completed 6 gross (0.14 net) wells in the Appalachian 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 investment 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 transaction 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 generally 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, 2024, 2023 and 2022.

Major Operators	2024	2023	2022
Operator A	*	11 %	12 %
Operator B	*	12 %	10 %
Operator C	*	*	10 %
Operator D	14 %	*	*

* 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, 2024, 2023, or 2022. 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 a syndicate of lenders, currently led by Bank of America, N.A, as administrative agent (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.

Our operated partnerships are governed by joint development agreements that outline the terms for the joint evaluation, acquisition, exploration, development, and production of hydrocarbons from jointly owned interests subject to such agreements. These agreements designate a third party as the operator of all jointly owned interests in the applicable development area, while Granite Ridge retains the right to manage and control acquisition costs and strategy, development costs, timing and rig schedules, well design and other development operations in exchange for a fee.

At the closing of the Business Combination, we entered into a Management Services Agreement ("MSA") with Grey Rock Administration, LLC (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, Ohio, 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. 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. Additionally, the CAA regulates the emission of methane from oil and gas facilities, which has been subject to uncertainty in recent years. Most recently, 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. The rules have been subject to legal challenge, and in February 2025, the D.C. Circuit Court granted the EPA's motion to hold the cases in abeyance while the agency reviews the final rules. While the Trump Administration may take action to repeal or modify the final rules, we cannot predict the substance or timing of such changes. 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 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, in May 2024, the EPA designated perfluorooctanoic acid ("PFOA") and perfluorooctanesulfonic acid ("PFOS"), which have been commonly used in a variety of industrial and consumer products, as hazardous substances. 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") was listed as endangered by the USFWS in May 2024. The DSL is found in southeastern New Mexico and adjacent portions of Texas. 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, thereby impacting our profitability.

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.

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 October 2024, the Colorado Energy and Carbon Management Commission (formerly the Colorado Oil and Gas Conversation Commission) finalized rules that 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 rules 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's Council on Environmental Quality ("CEQ") issued a final rule considered as "Phase I" of a two-phased approach to modifying the NEPA. Then, in May 2024, the CEQ finalized "Phase 2," which revised the implementing regulations of the procedural provisions of NEPA. The final rule was challenged by various states. Most recently, in November 2024, the U.S. Court of Appeals for the D.C. Circuit held that the CEQ lacks authority to issue NEPA regulations. As a result of this ruling and the new Trump Administration, there is significant uncertainty with respect to current and future NEPA regulations. For example, on January 20, 2025, President Trump issued an Executive Order directing the CEQ to issue new guidance and propose rescinding the existing NEPA regulations to "expedite and simplify the permitting process." And, on February 25, 2025, in response to this direction, the CEQ published an Interim Final Rule, requesting public comment through March 27, 2025. Any 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. President Biden recommitted the United States to the Paris Agreement on January 20, 2021; however, on January 20, 2025, President Trump signed an Executive Order once again withdrawing the U.S. from the Paris Agreement and from any commitments made under the United Nations Framework Convention on Climate Change. Additionally, President Trump revoked any purported financial commitment made by the U.S. pursuant to the same. The full impact of these actions is uncertain at this time. 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 have also recently been increasing financial risks for fossil fuel producers as certain 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, although this trend has waned recently, with several high-profile banks and institutional investors withdrawing from various associations that aim to limit the financing of such industries. 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") programs and goals, which are often aspirational, typically include voluntary targets related to environmental stewardship, social responsibility, and corporate governance matters, have become an increasing focus of certain investors and stockholders across the industry that often have conflicting priorities and perspectives. While reporting on ESG metrics, generally speaking, is currently voluntary, access to capital and investors has frequently favored companies with robust perceived strength in ESG topics or ESG programs in place. In March 2024, the SEC finalized rules establishing a framework for the reporting of climate risks, targets, and metrics. However, the future of the rule is uncertain at this time given that its implementation has been stayed pending the outcome of legal challenges. 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. 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.

Certain public statements with respect to ESG matters, such as emissions reduction goals, other environmental targets, or other commitments addressing certain social issues, are becoming increasingly subject to heightened scrutiny from public and governmental authorities related to the risk of potential "greenwashing," i.e., misleading information or false claims overstating potential ESG benefits. For example, the SEC has recently taken enforcement action against companies for ESG-related misconduct, including alleged greenwashing. Consequently, we may also be 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, estimation and evolving methodologies required with respect to collecting, calculating and reporting GHG emissions. Additionally, certain 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, 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, 2024, we had three 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 and exhibits 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.

In recent years, we have also made investments in operated partnerships, which comprise of investments in assets that are drilled, developed and operated by private operators. Our operated partnerships are structured such that we retain significant control over acquisition costs and strategy, development costs, timing and rig schedules, and well design. In these partnerships, while we have more influence over development decisions, we still rely on third-party operators for the execution of these decisions. The success of these partnerships is contingent upon the third-party operators' ability to effectively implement our development plans. Any failure or delay by these operators in executing our development strategies could materially and adversely affect our financial condition and results of operations.

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 (including failure to spud or place wells into production) could result in penalties, 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;
- 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, 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;
- 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, 2024, we had leases that were not developed that represented 6,160 net acres potentially expiring in 2025, 3,208 net acres potentially expiring in 2026 and 1,844 net acres potentially expiring in 2027 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 2024 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, 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 28% of our estimated net proved reserves volumes were classified as proved undeveloped as of December 31, 2024. 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.

We and 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 systems or 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 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. As of the date of this Annual Report, 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, the regulation of methane from oil and gas facilities has been subject to uncertainty in recent years. Most recently, 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. The rules have been subject to legal challenge, and in February 2025, the D.C. Circuit granted the EPA’s motion to hold the cases in abeyance while the agency reviews the final rules. While the Trump Administration may take action to repeal or modify the final rules, we cannot predict the substance or timing of such changes, if any. However, 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”) have 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 in October 2024 finalized rules that 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.

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 demand for corporate transparency and a demonstrated commitment to sustainability goals. ESG programs and goals, which are often aspirational, and which may include voluntary targets related to environmental stewardship, social responsibility, and corporate governance, have become an increasing, and sometimes conflicting, focus of certain investors and stakeholders, and companies that are perceived to be ESG laggards or are without robust ESG programs may find access to capital and investors more challenging in the future. Further, while reporting on most ESG information is, generally, currently voluntary, in March 2024, the SEC finalized rules establishing a framework for the reporting of climate risks, targets, and metrics. However, the future of the rule is uncertain at this time given that its implementation has been stayed pending the outcome of legal challenges as well as changed priorities under the new Presidential administration that could impact the fate of the final rules, though the timing and impact of any such changes are difficult to predict at this 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.

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.

Increased 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. Increased 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, and sometimes conflicting, 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, certain 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. While such ratings do not impact all investors' investment or 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 have implemented 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.

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 Information Technology General Controls 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 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, 2024, the Company had 5.0 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.

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, qualify 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 Partners GP III, L.P. ("Grey Rock Fund III"), pursuant to a Voting Agreement, dated as of August 25, 2023, by and among Grey Rock Fund III, Grey Rock Energy Partners GP II, L.P., and the other stockholders party thereto, controls 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.

The payment of dividends is at the discretion of our Board of Directors, and we cannot assure you that we will continue making dividend payments in the future.

We paid dividends of $57.5 million, or $0.44 per share, and $58.6 million, or $0.44 per share during the years ended December 31, 2024 and 2023, respectively. However, our Board of Directors is not obligated to make any future dividend payments. Instead, the declaration and payment of dividends are at the discretion of our Board of Directors and depend on a number of factors, including applicable law, economic conditions, financial condition, results of operations, projections, liquidity, earnings, legal requirements, restrictions in the Credit Agreement, and other factors our Board of Directors deems relevant. There can be no assurance that dividends will be declared in the future, or if declared, that the amount will be consistent with historical levels.

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 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.

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. Borrowers under credit agreements, letters of credit and certain other financial instruments with any 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.

Our operations and financial performance may be negatively affected directly or indirectly by changes in trade policies and tariffs.

In recent years, the United States increased tariffs for certain goods, which triggered other nations to also increase tariffs on certain of their goods. In recent weeks, the Trump administration has made many announcements regarding tariffs and the extent and duration of such tariffs remain uncertain. If maintained, the newly announced tariffs and the potential escalation of trade disputes could pose a risk to our business and also directly impact our operating expenses. For example, recently announced 25% tariffs on imported steel are likely to lead to increased material costs.

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.

We and the Manager engage 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 providers have experienced certain cybersecurity incidents, we are not aware of any risks from cybersecurity threats or incidents that have materially affected or are reasonably likely to materially affect the Company, including our business strategy, results of operations, or financial condition. 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 or our operators' information or operational 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 or our operators' information and operational 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 cybersecurity risks to the Audit Committee or the Board as appropriate.

Company management, including our Chief Financial Officer, meets as needed with relevant employees of the Manager, who collectively have over ten years of experience in managing cybersecurity related issues on behalf of the Manager, to discuss cybersecurity risks and incident trends and escalate 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, 2024, 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, 2024 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, 2024:

	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	17,372	104,292	34,754	64 %	$ 634,483	75 %
Proved developed non-producing	1,897	13,811	4,199	8 %	90,983	11 %
Proved undeveloped	8,918	38,666	15,362	28 %	116,463	14 %
Total proved	28,187	156,769	54,315	100 %	$ 841,929	100 %
Total proved developed	19,269	118,103	38,953	72 %	$ 725,466	86 %

(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, 2024 based on average prices of $76.32 per barrel of oil and $2.13 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 $23.9 million as of December 31, 2024. 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, 2024, 2023 and 2022 to the Standardized Measure of Discounted Future Net Cash Flows.

Standardized Measure Reconciliation

	December 31,		
(in thousands)	2024	2023	2022
Pre-tax present value of estimated future net revenues (Pre-Tax PV10%)	$ 841,929	$ 856,428	$ 1,559,123
Future income taxes, discounted at 10%	(120,961)	(134,520)	(293,196)
Standardized measure of discounted future net cash flows	$ 720,968	$ 721,908	$ 1,265,927

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, 2024, we had approximately 15,362 MBoe of proved undeveloped reserves as compared to 22,361 MBoe at December 31, 2023. A reconciliation of the change in proved undeveloped reserves during 2024 is as follows:

	MBoe
Estimated proved undeveloped reserves at December 31, 2023	22,361
Extensions and discoveries	4,765
Acquisition of reserves	3,733
Divestiture of reserves	(3,525)
Conversion to proved developed reserves	(8,684)
Revisions of previous estimates	(3,288)
Estimated proved undeveloped reserves at December 31, 2024	15,362

- *Extensions and discoveries*. In 2024, proved undeveloped reserves increased by 4,765 MBoe as a result of new proved undeveloped locations added primarily in the Permian Basin.

- *Acquisition of reserves*. In 2024, acquisitions of proved undeveloped reserves of 3,733 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 2024.

- *Divestiture of reserves.* In 2024, the Company divested of 3,525 MBoe of proved undeveloped reserves primarily in the Permian Basin.

- *Conversion to proved developed reserves.* In 2024, development of oil and natural gas properties resulted in the conversion of 8,684 MBoe from proved undeveloped reserves to proved developed reserves. We incurred development costs of approximately $138.4 million related to these locations.

- *Revisions of previous estimates*. In 2024, revisions of previous estimates decreased proved undeveloped reserves by 3,288 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, 2024, the PV-10 value of our proved undeveloped reserves amounted to 14% 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 75% 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, 2024, estimated future development costs required for the development of proved undeveloped reserves are projected to be approximately $253.5 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 2024 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, 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 Partner - Engineering, who is responsible for overseeing the internal preparation of our reserves pursuant to the MSA. The Manager's Partner - 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 reserve estimates, inclusive of decline curves, 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,		
	2024	2023	2022
Net Production:			
Oil (MBbl)	4,483	4,162	3,656
Natural gas (MMcf)	27,944	28,266	21,351
Total (MBoe)[1]	9,140	8,873	7,215
Average Daily Production:			
Oil (Bbl)	12,248	11,404	10,016
Natural gas (Mcf)	76,350	77,442	58,496
Total (Boe)[1]	24,973	24,311	19,765
Average Sales Prices:			
Oil (per Bbl)	$ 73.06	$ 76.18	$ 92.50
Natural gas and related product sales (per Mcf)	1.88	2.72	7.46
Realized price (per Boe)	41.58	44.41	68.94
Costs and Expenses (per Boe):			
Lease operating expenses	$ 6.29	$ 6.82	$ 6.19
Production and ad valorem taxes	$ 2.85	$ 3.12	$ 4.24
Depletion and accretion	$ 19.31	$ 18.11	$ 14.66
General and administrative	$ 2.70	$ 3.15	$ 1.97

(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, 2024, 2023 and 2022. 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,					
	2024		2023		2022	
	Gross	Net	Gross	Net	Gross	Net
Productive development wells	299	23.43	314	24.55	265	20.78
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 year ended December 31, 2023.

At December 31, 2024, we had 202 gross (14.85 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, 2024. A significant majority of our wells in the Permian, Bakken, DJ, and Appalachian 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, 2024					
	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian	714	—	714	64.70	—	64.70
Eagle Ford	129	100	229	27.40	7.30	34.70
Bakken	985	—	985	39.80	—	39.80
Haynesville	—	127	127	—	17.20	17.20
DJ	1,070	15	1,085	44.60	1.30	45.90
Appalachian	6	—	6	0.10	—	0.10
Total	2,904	242	3,146	176.60	25.80	202.40

The following table summarizes our cumulative gross and net productive oil and natural gas wells by basin at December 31, 2023:

	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

Developed and Undeveloped Acreage

The following table summarizes our estimated gross and net developed and undeveloped acreage by area at December 31, 2024.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Permian	48,731	8,427	14,787	6,638	63,518	15,065
Eagle Ford	25,750	4,243	5,815	2,344	31,565	6,587
Bakken	169,897	13,167	—	—	169,897	13,167
Haynesville	55,926	5,317	2,584	178	58,510	5,495
DJ	22,749	2,502	—	—	22,749	2,502
Appalachian	169	89	2,148	978	2,317	1,067
Total:	323,222	33,745	25,334	10,138	348,556	43,883

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 we can do so. The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2024 by area:

	2025		2026		2027 and Thereafter	
	Gross	Net	Gross	Net	Gross	Net
Permian(1)	9,485	3,662	5,976	3,104	1,148	724
Eagle Ford(1)	6,876	2,449	282	28	—	—
Haynesville	459	49	1,264	76	861	53
Appalachian	—	—	—	—	2,317	1,067
Total:	16,820	6,160	7,522	3,208	4,326	1,844

(1) Certain acreage within the basin is 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, 2024. 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 symbol "GRNT".

As of March 3, 2025 there were 72 holders of record of our common stock.

Dividend Policy

Subject to compliance with applicable law, and depending on, among other things, economic conditions, financial condition, results of operations, projections, liquidity, earnings, legal requirements, and restrictions in the Credit Agreement, we expect that Granite Ridge will pay quarterly cash dividends of $0.11 per share (or $0.44 per share per fiscal year). For information about dividends, see "Item 8. Financial Statements and Supplementary Data."

Repurchases of Equity Securities

During the quarter ended December 31, 2024, the Company repurchased shares of common stock from certain employees to satisfy the employees' tax withholding obligations in connection with the vesting of stock-based awards.

The following table sets forth our share repurchase activity for the 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, 2024 - October 31, 2024	—	$ —	—	$ —
November 1, 2024 - November 30, 2024	3,666	$ 6.40	—	$ —
December 1, 2024 - December 31, 2024	—	$ —	—	$ —

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 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 energy company which aims to provide shareholders with exposure similar to energy private equity through operated partnerships and traditional non-operated assets. We own assets in six prolific unconventional basins across the United States. We aim to deliver a diversified portfolio with best-in-class full cycle returns by investing in a large number of high-graded opportunities developed by proven public and private operators. We focus on success as measured by total shareholder returns, which we seek to balance with a low leverage profile.

As of December 31, 2024, we owned an interest in 3,146 gross (202 net) producing wells, 323,222 gross (33,745 net) developed acres, and 25,334 gross (10,138 net) undeveloped acres, all located in the United States.

Our average daily production for the year ended December 31, 2024 was 24,973 Boe per day.

Business Combination

On October 24, 2022 (the “Closing Date”), Granite Ridge and Executive Network Partnering 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”).

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, Denver-Julesburg and Appalachian 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 2024, 2023 and 2022 was $(3.57) per barrel, $(1.40) per barrel and $(1.89) per barrel, respectively. Our natural gas price differential during 2024, 2023 and 2022 was $(0.31) per Mcf, $0.19 per Mcf and $0.91 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, 2024, 2023 and 2022.

	December 31,		
	2024	2023	2022
Average NYMEX Prices[(1)]			
Oil (per Bbl)	$ 76.63	$ 77.58	$ 94.39
Natural gas (per Mcf)	$ 2.19	$ 2.53	$ 6.55

(1) Based on average NYMEX closing prices.

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, 2024 and 2023. For similar operating and financial data and discussion of our 2023 results compared to our 2022 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, 2023, which was filed with the SEC on March 8, 2024. 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,	
	2024	2023
Net Sales (in thousands):		
Oil sales	$ 327,491	$ 317,099
Natural gas and related product sales	52,539	76,970
Revenues	380,030	394,069
Net Production:		
Oil (MBbl)	4,483	4,162
Natural gas (MMcf)	27,944	28,266
Total (MBoe)(1)	9,140	8,873
Average Daily Production:		
Oil (Bbl)	12,248	11,404
Natural gas (Mcf)	76,350	77,442
Total (Boe)(1)	24,973	24,311
Average Sales Prices:		
Oil (per Bbl)	$ 73.06	$ 76.18
Effect of gain (loss) on settled oil derivatives on average price (per Bbl)	0.34	1.10
Oil net of settled oil derivatives (per Bbl)(2)	$ 73.40	$ 77.28
Natural gas and related product sales (per Mcf)	$ 1.88	$ 2.72
Effect of gain (loss) on settled natural gas derivatives on average price (per Mcf)	0.53	0.65
Natural gas and related product sales net of settled natural gas derivatives (per Mcf)(2)	$ 2.41	$ 3.37
Realized price on a Boe basis excluding settled commodity derivatives	$ 41.58	$ 44.41
Effect of gain (loss) on settled commodity derivatives on average price (per Boe)	1.79	2.58
Realized price on a Boe basis including settled commodity derivatives(2)	$ 43.37	$ 46.99
Operating Expenses (in thousands):		
Lease operating expenses	$ 57,461	$ 60,521
Production and ad valorem taxes	26,007	27,707
Depletion and accretion expense	176,529	160,662
Impairments of long-lived assets	36,369	26,496
General and administrative	24,649	27,920
Costs and Expenses (per Boe):		
Lease operating expenses	$ 6.29	$ 6.82
Production and ad valorem taxes	$ 2.85	$ 3.12
Depletion and accretion	$ 19.31	$ 18.11
Impairments of long-lived assets	$ 3.98	$ 2.99
General and administrative	$ 2.70	$ 3.15
Net Producing Wells at Period-End:	202.40	176.50

(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. Our oil and natural gas sales for the year ended December 31, 2024 decreased 4% from the year ended December 31, 2023. Oil revenues for the year ended December 31, 2024 increased by 3% compared to the same period in 2023, driven by an 8% increase in production, partially offset by a 4% decrease in realized prices, excluding the effect of settled derivatives. Natural gas revenues decreased by 32% for the year ended December 31, 2024 compared to 2023, driven by a 31% decrease in realized natural gas prices, excluding the effect of settled commodity derivatives, and a 1% decrease in production.

Production from oil and gas properties increased because of drilling success and the acquisition of additional net revenue interests. This increase in total 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 176.50 net wells in 2023 to 202.40 net wells in 2024.

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

	Year Ended December 31,	
	2024	2023
Net Production:		
Oil (MBbl)		
Permian	2,956	2,656
Eagle Ford	638	529
Bakken	561	665
Haynesville	—	—
DJ	322	312
Appalachian	6	—
Total	4,483	4,162
Natural Gas (MMcf)		
Permian	11,229	9,146
Eagle Ford	3,847	3,055
Bakken	1,235	1,105
Haynesville	9,264	12,251
DJ	2,345	2,709
Appalachian	24	—
Total	27,944	28,266
Total (MBoe)		
Permian	4,828	4,180
Eagle Ford	1,279	1,038
Bakken	767	849
Haynesville	1,544	2,042
DJ	712	764
Appalachian	10	—
Total	9,140	8,873

Lease Operating Expenses

Lease operating expenses were $57.5 million ($6.29 per Boe) for the year ended December 31, 2024, a decrease of 5% from $60.5 million ($6.82 per Boe) for 2023. The decrease was primarily due to a decrease of $1.6 million in transportation and gathering expenses related to certain take in-kind arrangements on natural gas volumes, which have declined in the Haynesville area. In addition, workover and repair and maintenance expenses for the year ended December 31, 2024 are lower than the same period of 2023, partially offset by an increase in certain other lease operating expenses as a result of an increase in well count due to acquisitions and additional wells successfully drilled and completed.

Production and Ad Valorem Taxes

We generally pay production taxes based on realized oil and natural gas sales. Production taxes were $21.0 million ($2.30 per Boe) for the year ended December 31, 2024 compared to $24.9 million ($2.81 per Boe) for 2023. As a percentage of oil and natural gas sales, our production taxes were 6% in 2024 and 2023.

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 increased during the year ended December 31, 2024 as compared to 2023, primarily due to additional wells drilled and completed and new wells acquired.

Depletion and Accretion

Depletion and accretion was $176.5 million ($19.31 per Boe) for the year ended December 31, 2024, an increase of 10% from $160.7 million ($18.11 per Boe) in 2023. 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 years ended December 31, 2024 and 2023, we recognized impairment expense of $36.4 million and $26.5 million, respectively. As of December 31, 2024, as a result of widening differentials and higher production cost assumptions, it was determined that the carrying amount of proved oil and gas properties in the Bakken exceeded undiscounted future net cash flows. As a result, an impairment of $35.6 million was recorded to write-down the carrying value to the estimated fair value of the proved oil and gas properties. Additionally, for the year ended December 31, 2024, an impairment of $0.7 million to the Company's unproved properties in the Permian Basin as the operator of those properties no longer intends to drill certain locations.

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, 2024 and 2023:

	Year Ended December 31,	
(in thousands)	**2024**	**2023**
General and administrative expenses	$ 22,351	$ 25,758
Non-cash stock-based compensation	2,298	2,162
Total general and administrative expenses	$ 24,649	$ 27,920

Total general and administrative expenses were $24.6 million ($2.70 per Boe) for the year ended December 31, 2024, a decrease of 12% from $27.9 million ($3.15 per Boe) in 2023. The decrease was primarily due to $2.5 million of costs directly related to the Warrant Exchange in 2023.

Gain/(Loss) on Derivatives – Commodity Derivatives

The following table sets forth the gain (loss) on derivatives for the years ended December 31, 2024 and 2023:

(in thousands)	Year Ended December 31, 2024	2023
Gain (loss) on commodity derivatives		
Oil derivatives	$ (10,260)	$ 6,459
Natural gas derivatives	9,352	19,085
Total	$ (908)	$ 25,544

The following table represents our net cash receipts from (payments on) derivatives for the years ended December 31, 2024 and 2023:

(in thousands)	Year Ended December 31, 2024	2023
Net cash receipts from (payments on) commodity derivatives		
Oil derivatives	$ 1,503	$ 4,576
Natural gas derivatives	14,860	18,319
Total	$ 16,363	$ 22,895

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 $18.5 million for the year ended December 31, 2024 compared to $5.3 million for 2023. The increase in interest expense was primarily due to the increase in interest rates 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 during 2023 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)

For the year ended December 31, 2024, we recorded income tax expense of $6.2 million, which included current income tax expense of $0.2 million and deferred income tax expense of $6.0 million. Our effective income tax rate of 24.9% for the year ended December 31, 2024 differs from the federal statutory rate due primarily to the impact of certain discrete items, state income taxes and changes in state tax rates. For the year ended December 31, 2023, we recorded income tax expense of $24.5 million, which included current income tax expense of $0.2 million and deferred income tax expense of $24.3 million. Our effective income tax rate of 23.2% for the year ended December 31, 2023 differed from the federal statutory rate of 21% primarily due to the impact of certain discrete items and state 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, 2024, we had $205.0 million of debt outstanding under our Credit Agreement. We had $129.1 million of liquidity as of December 31, 2024, consisting of $119.7 million of committed borrowing availability under the Credit Agreement and $9.4 million of cash on hand. On November 1, 2024, the Company and its lenders entered into the Fourth Amendment to the Credit Agreement, which amended the Credit Agreement to, among other things, increase the borrowing base and aggregate elected commitments from $300 million to $325 million. 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 $57.5 million, or $0.44 per share, and $58.6 million, or $0.44 per share, during the years ended December 31, 2024 and 2023, respectively. On February 14, 2025, our Board of Directors declared a cash dividend of $0.11 per share for the first quarter of 2025 that will be paid on March 14, 2025 to stockholders of record as of February 28, 2025. 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. During the year ended December 31, 2023, the Company repurchased 5,651,707 shares under the program at an aggregate cost of $36.1 million. 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, 2024, 2023 and 2022 are presented below:

	Year Ended December 31,		
(in thousands)	2024	2023	2022
Net cash provided by operating activities	$ 275,733	$ 302,867	$ 346,389
Net cash used in investing activities	(310,768)	(356,676)	(230,562)
Net cash provided by (used in) financing activities	33,724	13,406	(76,848)
Net change in cash	$ (1,311)	$ (40,403)	$ 38,979

Cash Flows Provided by 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 $27.1 million decrease in operating cash flows during the year ended December 31, 2024 as compared to 2023 was primarily due to the decrease in oil and natural gas sales and deferred income taxes during 2024 as compared to 2023. Our net cash provided by operating activities included a benefit of $0.9 million and a benefit of $4.6 million for the years ended December 31, 2024 and 2023, 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 Used in Investing Activities

For the year ended December 31, 2024, our net cash used in investing activities was $310.8 million, which consisted primarily of $285.8 million of capital expenditures for oil and natural gas properties and $61.2 million of acquisitions of oil and natural gas properties. These cash flows used in investing activities are partially offset by cash proceeds from disposal of oil and natural gas properties of $14.0 million and refund of advances from operators of $19.7 million during 2024.

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. These cash flows used in investing activities are partially offset by cash proceeds from refund of advances from operators of $2.5 million.

Cash Flows Provided by (Used in) Financing Activities

For the year ended December 31, 2024, our net cash provided by financing activities was $33.7 million primarily due to $95.0 million of net borrowings under our Credit Agreement, partially offset by $57.5 million of dividends paid on our common stock.

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.

Granite Ridge Credit Agreement

At December 31, 2024, the Company had outstanding borrowings of $205.0 million and $0.3 million of letters of credit issued and outstanding under the Credit Agreement, resulting in availability of $119.7 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.

On October 24, 2022, Granite Ridge entered into a senior secured revolving credit agreement (as amended, the “Credit Agreement”) among Granite Ridge, as borrower, currently led by Bank of America, N.A., 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.

On April 1, 2024, the Company entered into the Resignation, Appointment, Assignment and Third Amendment to Credit Agreement (the “Third Amendment”) which amended the Credit Agreement to, among other things, (a) appoint a new administrative agent and L/C Issuer (as defined therein) (b) increase the size of the lender group by adding nine new banks, with one bank exiting the facility, (c) increase the borrowing base from $275.0 million to $300.0 million, and (d) increase the aggregate elected commitments from $240.0 million to $300.0 million.

On November 1, 2024, the Company and its lenders entered into the Fourth Amendment to the Credit Agreement, which amended the Credit Agreement to, among other things, (a) increase the borrowing base from $300.0 million to $325.0 million, and (b) increase the aggregate elected commitments from $300.0 million to $325.0 million.

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. SOFR loans 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 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 Company's weighted average effective interest rate under the Credit Agreement as of December 31, 2024 and 2023 was 8.12% and 8.71%, respectively.

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 each 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.

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, 2024, 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, 2024, we had $205.0 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 pay the Manager an annual services fee of $10.0 million and 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 2025, we are budgeting approximately $300 million to $320 million in total planned capital expenditures. 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, 2024, approximately 28% 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, 2024.

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, 2024, 2023, and 2022, we recognized depletion expense of $175.7 million, $160.2 million and $105.3 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 certain proved undeveloped locations. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of 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 and risk-adjusted probable and possible reserves. 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, using the income or market approach, 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, 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.

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.

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.

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 the 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, 2024, a 10% increase in average commodity prices would have decreased the fair value of commodity derivatives by $19.3 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, 2024, 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 $205.0 million outstanding under our Credit Agreement at December 31, 2024. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $2.1 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, 2024.

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, 2024, 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, 2024, our disclosure controls and procedures were effective at a level of reasonable assurance.

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, 2024.

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*

Trading Plans

None of our directors or "officers," as defined in Rule 16a-1(f) under the Exchange Act, adopted or terminated a Rule 10b5-1 trading plan or arrangement or a non-Rule 10b5-1 trading plan or arrangement, as defined in Item 408(c) of Regulation S-K, during the fiscal quarter covered by this Annual Report.

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, 2024.

Granite Ridge has adopted a written code of business conduct and ethics that applies to its directors, officers, employees and individuals providing services to Granite Ridge pursuant to the MSA, in accordance with applicable federal securities laws, a copy of which is available on Granite Ridge’s website at www.graniteridge.com. Granite Ridge intends to disclose on its website any future amendments of the code of ethics or waivers that exempt any principal executive officer, principal financial officer, principal accounting officer or controller, persons performing similar functions or Granite Ridge's directors from provisions in the code of business conduct and ethics.

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, 2024.

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, 2024.

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, 2024.

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, 2024.

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, 2024 and 2023

Consolidated Statements of Operations for the Years Ended December 31, 2024, 2023 and 2022

Consolidated Statements of Cash Flows for the Years Ended December 31, 2024, 2023 and 2022

Consolidated Statements of Stockholders Equity for the Years Ended December 31, 2024, 2023 and 2022

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).
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).

Exhibit No.	Description
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	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 for grants made prior to March 5, 2025 (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 Restricted Stock Award Agreement under the Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan for grants made on and after March 5, 2025.
10.6#	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).
10.7#	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).
10.8	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).
10.8.1	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).
10.8.2	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 (incorporated by reference to Exhibit 10.7.2 to the Company's Annual Report on Form 10-K filed with the SEC on March 8, 2024).
10.8.3	Resignation, Appointment, Assignment and Third Amendment to Credit Agreement, dated as of April 1, 2024, by and among Granite Ridge Resources, Inc., as borrower, Texas Capital Bank, as resigning administrative agent, Bank of America, N.A., as successor 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 April 4, 2024).
10.8.4	Fourth Amendment to Credit Agreement, dated as of November 1, 2024, by and among Granite Ridge Resources, Inc., as borrower, the guarantors party thereto, Bank of America, N.A., 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 4, 2024).
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).

Exhibit No.	Description
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).
10.13#	Executive Change in Control Termination Agreement between Kimberly Weimer and Granite Ridge Resources, Inc. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 9, 2024).
19.1*	Granite Ridge Resources, Inc. Insider Trading Policy.
23.1*	Consent of Forvis Mazars, 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 (incorporated by reference to Exhibit 97.1 to the Company's Annual Report on Form 10-K filed with the SEC on March 8, 2024).
99.1*	Reserve Report of Granite Ridge Resources as of December 31, 2024.
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 6, 2025	By:	/s/ LUKE C. BRANDENBERG	
		Name:	Luke C. Brandenberg
		Title:	*President and Chief Executive Officer*
March 6, 2025	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 6, 2025
/s/ Tyler S. Farquharson Tyler S. Farquharson	Chief Financial Officer (Principal Financial Officer)	March 6, 2025
/s/ Kimberly A. Weimer Kimberly A. Weimer	Chief Accounting Officer (Principal Accounting Officer)	March 6, 2025
/s/ Matt Miller Matt Miller	Director and Co-Chairman of the Board	March 6, 2025
/s/ Griffin Perry Griffin Perry	Director and Co-Chairman of the Board	March 6, 2025
/s/ Amanda N. Coussens Amanda N. Coussens	Director	March 6, 2025
/s/ Thaddeus Darden Thaddeus Darden	Director	March 6, 2025
/s/ Michele J. Everard Michele J. Everard	Director	March 6, 2025
/s/ Kirk Lazarine Kirk Lazarine	Director	March 6, 2025
/s/ John McCartney John McCartney	Director	March 6, 2025

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, 2024 and 2023, 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, 2024, 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, 2024 and 2023, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2024, 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 Mazars, LLP

We have served as the Company's auditor since 2015.
Dallas, Texas
March 6, 2025

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

(in thousands, except par value and share data)	December 31, 2024	December 31, 2023
ASSETS		
Current assets:		
Cash	$ 9,419	$ 10,430
Revenue receivable	69,692	72,934
Advances to operators	19,959	4,928
Prepaid and other current assets	3,831	1,716
Derivative assets - commodity derivatives	537	11,117
Equity investments	31,783	50,427
Total current assets	135,221	151,552
Property and equipment:		
Oil and gas properties, successful efforts method	1,540,021	1,236,683
Accumulated depletion	(643,051)	(467,141)
Total property and equipment, net	896,970	769,542
Long-term assets:		
Derivative assets - commodity derivatives	—	1,189
Other long-term assets	4,288	4,821
Total long-term assets	4,288	6,010
Total assets	$ 1,036,479	$ 927,104
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 99,440	$ 60,875
Other liabilities	546	1,204
Derivative liabilities - commodity derivatives	1,822	—
Total current liabilities	101,808	62,079
Long-term liabilities:		
Long-term debt	205,000	110,000
Derivative liabilities - commodity derivatives	3,679	—
Asset retirement obligations	10,693	9,391
Deferred tax liability	79,946	73,989
Total long-term liabilities	299,318	193,380
Total liabilities	401,126	255,459
Commitments and contingencies (Note 11)		
Stockholders' Equity:		
Common stock, $0.0001 par value, 431,000,000 shares authorized, 136,417,677 and 136,040,777 issued at December 31, 2024 and 2023, respectively	14	14
Additional paid-in capital	655,472	653,174
Retained earnings	16,047	54,782
Treasury stock, at cost, 5,683,921 and 5,677,627 shares at December 31, 2024 and 2023, respectively	(36,180)	(36,325)
Total stockholders' equity	635,353	671,645
Total liabilities and stockholders' equity	$ 1,036,479	$ 927,104

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

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)	Year Ended December 31, 2024	2023	2022
Revenues:			
Oil and natural gas sales	$ 380,030	$ 394,069	$ 497,417
Operating costs and expenses:			
Lease operating expenses	57,461	60,521	44,678
Production and ad valorem taxes	26,007	27,707	30,619
Depletion and accretion expense	176,529	160,662	105,752
Impairments of long-lived assets	36,369	26,496	—
General and administrative	24,649	27,920	14,223
Other, net	(241)	176	—
Total operating costs and expenses	320,774	303,482	195,272
Net operating income	59,256	90,587	302,145
Other income (expense):			
Gain (loss) on derivatives - commodity derivatives	(908)	25,544	(25,324)
Interest expense, net	(18,470)	(5,315)	(1,989)
Gain (loss) on derivatives - common stock warrants	—	(5,742)	362
Gain (loss) on equity investments	(15,183)	508	—
Other income	271	—	—
Total other income (expense)	(34,290)	14,995	(26,951)
Income before income taxes	24,966	105,582	275,194
Income tax expense	6,207	24,483	12,850
Net income	$ 18,759	$ 81,099	$ 262,344
Net income per share:			
Basic	$ 0.14	$ 0.61	$ 1.97
Diluted	$ 0.14	$ 0.61	$ 1.97
Weighted-average number of shares outstanding:			
Basic	130,189	133,093	132,923
Diluted	130,227	133,109	133,074

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, 2022	$ 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
Grants of restricted stock	—	383	—	—	—	—	—	—
Forfeitures of restricted stock	—	(6)	—	—	—	—	—	—
Stock-based compensation	—	—	—	2,298	—	—	—	2,298
Purchase of treasury stock	—	—	—	—	—	(6)	(40)	(40)
Excise tax adjustments on treasury stock	—	—	—	—	—	—	185	185
Common stock dividend declared ($0.44 per share)	—	—	—	—	(57,494)	—	—	(57,494)
Net income	—	—	—	—	18,759	—	—	18,759
As of December 31, 2024	$ —	136,418	$ 14	$ 655,472	$ 16,047	(5,684)	$ (36,180)	$ 635,353

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)	2024	2023	2022
Operating activities:			
Net income	$ 18,759	$ 81,099	$ 262,344
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion and accretion expense	176,529	160,662	105,752
Impairments of long-lived assets	36,369	26,496	—
(Gain) loss on derivatives - commodity derivatives	908	(25,544)	25,324
Net cash receipts from (payments on) commodity derivatives	16,363	22,895	(42,437)
Stock-based compensation	2,298	2,162	—
Amortization of loan origination costs	3,540	1,260	159
(Gain) loss on derivatives - common stock warrants	—	5,742	(362)
(Gain) loss on equity investments	15,183	(508)	—
Deferred income taxes	5,958	24,274	12,850
Other	(1,034)	(313)	—
Increase (decrease) in cash attributable to changes in operating assets and liabilities:			
Revenue receivable	3,288	(846)	(24,989)
Other receivable	183	103	—
Accrued expenses	(1,153)	4,550	9,838
Prepaid and other current assets	(1,411)	485	(2,095)
Other payable	(47)	350	5
Net cash provided by operating activities	275,733	302,867	346,389
Investing activities:			
Capital expenditures for oil and natural gas properties	(285,796)	(282,390)	(185,497)
Acquisition of oil and natural gas properties	(61,197)	(76,810)	(49,191)
Deposit on acquisition	(887)	—	(1,899)
Refund of advances to operators	19,655	2,464	1,180
Proceeds from the disposal of oil and natural gas properties	13,995	60	4,845
Proceeds from the sale of equity investments	3,462	—	—
Net cash used in investing activities	(310,768)	(356,676)	(230,562)
Financing activities:			
Proceeds from borrowing on credit facilities	110,000	162,500	21,000
Repayments of borrowing on credit facilities	(15,000)	(52,500)	(72,100)
Deferred financing costs	(3,340)	(2,616)	(3,237)
Payment of expenses related to formation of Granite Ridge Resources, Inc.	—	(43)	(18,456)
Purchase of treasury shares	(442)	(35,353)	(216)
Payment of dividends	(57,494)	(58,587)	(10,664)
Proceeds from issuance of common stock	—	5	6,825
Net cash provided by (used in) financing activities	33,724	13,406	(76,848)
Net change in cash and restricted cash	(1,311)	(40,403)	38,979
Cash and restricted cash at beginning of year	10,730	51,133	12,154
Cash and restricted cash at end of year	$ 9,419	$ 10,730	$ 51,133
Supplemental disclosure of cash flow information:			
Cash paid during the year for interest	$ (14,472)	$ (4,825)	$ (2,286)
Cash paid during the year for income taxes	$ (197)	$ (742)	$ (98)
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	$ 36,736	$ (12,325)	$ 48,187
Advances to operators applied to development of oil and natural gas properties	$ 121,922	$ 98,224	$ 103,535
Cash and restricted cash:			
Cash	$ 9,419	$ 10,430	$ 50,833
Restricted cash included in other long-term assets	—	300	300
Cash and restricted cash	$ 9,419	$ 10,730	$ 51,133

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” or the “Company”) 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, dated as of May 16, 2022, by and among ENPC, Granite Ridge, and certain other parties thereto (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 under the terms of the Sponsor Agreement 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 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 periods 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 the 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.

The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("U.S. GAAP").

Segment Reporting

The Company operates in one reporting 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 reporting segment generates revenue through the sale of oil and natural gas. The Company's chief operating decision maker ("CODM"), who is the Company's Chief Executive Officer, manages operations on a consolidated basis for purposes of evaluating operational performance and allocating resources. Net income, as reported within the Company's consolidated statement of operations, is used by the CODM to assess performance for the oil and natural gas development, exploration and production segment. Significant segment expenses are the same as those reported in the consolidated statement of operations. Total assets, as reported within the Company's consolidated balance sheets, is the measure of segment assets.

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 workover 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 assets acquired and liabilities assumed for business combinations, fair value of oil and natural gas properties for impairment, 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.

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.

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. As of December 31, 2023, the Company had $0.3 million of cash classified as restricted. The restricted balance related to a cash deposit for two standby letters of credit associated with oil and natural gas mining lease agreements. During 2024, the standby letters of credit were terminated and, as a result, the Company has no restricted cash at December 31, 2024.

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 are typically received from the operator one to three months after production. As of December 31, 2024 and 2023, the Company had an allowance for expected credit losses of $0.2 million, which was based on a historical loss rate.

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 natural gas properties on the consolidated statements of cash flows.

Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for oil and natural 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, 2024 or 2023.

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 $175.7 million, $160.2 million and $105.3 million for the years ended December 31, 2024, 2023, and 2022, 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. Costs incurred to maintain wells and related equipment are charged to expense as incurred. 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. No interest costs were capitalized for the years ended December 31, 2024 and 2022. For the year ended December 31, 2023, $1.0 million of interest costs were capitalized.

Gains or losses are recorded for sales or dispositions of proved oil and gas properties which constitute an entire depletion base or 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. Dispositions of individual properties that do not significantly alter the depletion rates are generally accounted for as adjustments to capitalized costs with no gain or loss recorded.

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 is recognized at that time. The fair value of impaired assets is determined using the market or income valuation approach. The income approach is calculated using a discounted cash flow model. Discounted future cash flows use a discount rate similar to that used by market participants, or comparable market value if available. 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. The Company recorded proved property impairment of $35.6 million and $26.5 million for the years ended December 31, 2024 and 2023, respectively. There were no proved property impairment indicators for the year ended December 31, 2022.

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 recorded unproved oil and gas properties impairment of $0.7 million for the year ended December 31, 2024. The Company did not record any unproved oil and gas properties impairment for the years ended December 31, 2023 or 2022.

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 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 in 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.

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. 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.

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.

On June 4, 2024, the 2.0% cumulative mandatorily convertible preferred securities were converted into the equivalent number of shares of Vital Energy’s common stock. During the year ended December 31, 2024, the Company divested 75,000 shares of Vital Energy’s common stock and realized a gain on sale of $0.1 million included in gain (loss) on equity investments within the Company’s consolidated statements of operations.

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 in the consolidated statements of operations. For the preferred stock that did not have a readily determinable fair value, the Company did not elect the measurement alternative in ASC 321 and instead accounted for the preferred stock at fair value with unrealized gains and losses recorded through net income for the periods until the preferred stock was converted into common stock. For the year ended December 31, 2024, an unrealized loss of $15.3 million is included in gain (loss) on equity investments within the Company's consolidated statements of operations that reflects the change in fair value of the common stock. For the year ended December 31, 2023, the Company recorded an unrealized gain of $0.5 million related to the Vital Energy common and preferred shares.

Asset Retirement Obligations

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 obligations relate 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 the 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 consolidated balance sheets. Variances between the Company's estimated revenue and actual payments are recorded in the month the payment is received; however, differences have been and are insignificant.

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.

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

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 revenue deductions such as gathering, transportation and compression costs incurred by the operator. 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 unprocessed gas in kind at the operator's wellhead, representing its proportionate share of its natural gas production, in lieu of receiving a net payment from the operator. The Company currently takes certain natural gas volumes in kind in lieu of monetary settlement. When the Company elects to take volumes in kind, it pays third parties to transport the natural gas 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 volumes to downstream customers are recorded in lease operating expenses in the consolidated statements of operations.

Disaggregated Oil and Natural Gas Revenues

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 six geographic areas in the United States: the Eagle Ford Basin (Texas), the Permian Basin (Texas/New Mexico), the Haynesville Basin (Texas/Louisiana), the Denver-Julesburg "DJ" Basin (Colorado), the Bakken Basin (Montana/North Dakota), and Appalachian Basin (Ohio). 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 and natural gas revenues by basin for the years ended December 31, 2024, 2023 and 2022.

	Year Ended December 31,		
(in thousands)	**2024**	**2023**	**2022**
Oil	$ 327,491	$ 317,099	$ 338,163
Natural gas	52,539	76,970	159,254
Total	$ 380,030	$ 394,069	$ 497,417
Permian	$ 238,052	$ 237,730	$ 266,856
Eagle Ford	54,399	46,410	64,879
Bakken	40,358	51,128	64,999
Haynesville	16,776	24,833	62,743
DJ	29,980	33,968	37,880
SCOOP/STACK	—	—	60
Appalachian	465	—	—
Total	$ 380,030	$ 394,069	$ 497,417

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, 2024, 2023 and 2022 were approximately $21.0 million, $24.9 million and $26.9 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, 2024, 2023 and 2022 were approximately $5.0 million, $2.8 million and $3.7 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.

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 of stock-based compensation awards as they occur.

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

In December 2023, the FASB issued ASU 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.

In November 2024, the FASB issued ASU 2024-03, "Disaggregation of Income Statement Expenses", ("ASU 2024-03") which requires enhanced disclosure about specific types of expenses included in the expense captions presented on the face of the consolidated income statement as well as disclosures about selling expenses. ASU 2024-03 is effective for annual periods beginning after December 15, 2026 and interim periods beginning after December 15, 2027. Early adoption is permitted. The Company has not early adopted the standard and is currently assessing the effect that ASU 2024-03 will have on its disclosures.

Recently Issued and Applicable Accounting Pronouncements (Issued and Adopted)

The FASB issued ASU 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 receivable 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 receivable.

In November 2023, the FASB issued ASU 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. ASU 2023-07 was effective for annual periods beginning after December 15, 2023, and is effective for interim periods beginning after December 15, 2024. The Company adopted this accounting standard beginning in this Annual Report on Form 10-K. See *Segment Reporting* section of this note for enhanced disclosures resulting from the adoption of ASU 2023-07.

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 speculative 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 its 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, 2024.

	2025					2026
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Total
Collars (oil)						
Volume (Bbl)	764,903	623,266	522,210	494,000	2,404,379	788,980
Weighted-average floor price ($/Bbl)	$ 61.59	$ 60.27	$ 61.65	$ 60.00	$ 60.93	$ 60.00
Weighted-average ceiling price ($/Bbl)	$ 78.52	$ 77.82	$ 79.43	$ 77.23	$ 78.27	$ 69.68
Collars (natural gas)						
Volume (Mcf)	4,134,179	1,075,438	2,441,757	2,662,615	10,313,989	8,154,446
Weighted-average floor price ($/Mcf)	$ 3.30	$ 3.00	$ 3.00	$ 3.10	$ 3.14	$ 3.29
Weighted-average ceiling price ($/Mcf)	$ 4.56	$ 3.75	$ 3.75	$ 3.89	$ 4.11	$ 4.06
Swaps (natural gas)						
Volume (Mcf)	—	2,548,520	717,450	212,350	3,478,320	1,253,400
Weighted-average price ($/Mcf)	$ —	$ 3.19	$ 3.17	$ 3.16	$ 3.18	$ 3.41

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, 2024, 2023 and 2022:

	Year Ended December 31,		
(in thousands)	2024	2023	2022
Gain (loss) on commodity derivatives			
Oil derivatives	$ (10,260)	$ 6,459	$ (14,985)
Natural gas derivatives	9,352	19,085	(10,339)
Total	$ (908)	$ 25,544	$ (25,324)

The following table represents the Company’s net cash receipts (payments on) commodity derivatives for the years ended December 31, 2024, 2023 and 2022:

	Year Ended December 31,		
(in thousands)	2024	2023	2022
Net cash receipts from (payments on) commodity derivatives			
Oil derivatives	$ 1,503	$ 4,576	$ (23,695)
Natural gas derivatives	14,860	18,319	(18,742)
Total	$ 16,363	$ 22,895	$ (42,437)

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 during the period they were outstanding.

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 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, 2024 and 2023:

	December 31, 2024		December 31, 2023	
(in thousands)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Assets:				
Derivative instruments - commodity derivatives	$ 537	$ 537	$ 12,306	$ 12,306
Equity investments	$ 31,783	$ 31,783	$ 50,427	$ 50,427
Liabilities:				
Revolving credit facilities	$ 205,000	$ 205,000	$ 110,000	$ 110,000
Derivative instruments - commodity derivatives	$ 5,501	$ 5,501	$ —	$ —

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.

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 was 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. The fair value of the investment in preferred stock was 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 are supported by observable levels at which transactions are executed in the marketplace.

On June 4, 2024, the 2.0% cumulative mandatorily convertible preferred securities of Vital Energy were converted into 541,155 shares of common stock of Vital Energy. Prior to this conversion, the common shares of Vital Energy owned by the Company were not entitled to vote and bore a restricted legend to that effect. As of December 31, 2024, the Company held 1,027,907 shares of Vital Energy’s common stock, for which the fair value is a Level 1 measurement.

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, 2024 and 2023. The Company nets the fair value of commodity derivative instruments by counterparty in the Company’s consolidated balance sheets.

	December 31, 2024					
	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	$ 31,783	$ —	$ —	$ 31,783	$ —	$ 31,783
Assets (at fair value):						
Commodity derivatives – current portion	$ —	$ 2,053	$ —	$ 2,053	$ (1,516)	$ 537
Liabilities (at fair value):						
Commodity derivatives – current portion	—	(3,338)	—	(3,338)	1,516	(1,822)
Commodity derivatives – noncurrent portion	—	(3,679)	—	(3,679)	—	(3,679)
Net derivative instruments	$ —	$ (4,964)	$ —	$ (4,964)	$ —	$ (4,964)

	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

Fair Values – Nonrecurring

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, 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 estimated fair values of its long-lived assets using the market and income valuation approaches. The income approach is calculated 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 and unproved reserves and (vii) discount rate. The expected future net cash flows are generally discounted using a discount rate which has approximated 10 percent for proved developed producing reserves and an appropriate market discount rate based on risk for other reserve categories. The Company uses the market approach by identifying market comparisons of recent transactions of oil and gas properties that share geographical and reserve characteristics to assess the fair value of the Company's assets. These are classified as Level 3 fair value assumptions.

As of December 31, 2024, the Company’s estimates of commodity prices for purposes of determining discounted future cash flows, which are based on the NYMEX strip, ranged from a 2025 price of $69.87 per barrel of oil decreasing to a 2029 price of $63.07 per barrel of oil. Natural gas prices ranged from a 2025 price of $3.53 per Mcf of natural gas increasing to a 2029 price of $3.58 per Mcf. Both oil and natural gas commodity prices for this purpose were held flat after 2029.

As of December 31, 2023, the Company’s estimates of commodity prices for purposes of determining discounted 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.

Bakken Impairment

In the fourth quarter of 2024, there were indicators that the carrying value of the Company's Bakken proved oil and gas properties may be impaired due to widening differentials and higher production cost assumptions. As a result of the impairment evaluation, where the market and income approach were utilized to assess fair value, the Company recorded impairment of $35.6 million, which is included in impairment of long-lived assets within the consolidated statements of operations.

Haynesville Impairment

In the fourth quarter of 2023, there were indicators that the carrying value of the Company's Haynesville proved oil and gas 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 to assess fair value, the Company recorded impairment of $26.5 million, which is included in impairment of long-lived assets within the consolidated statements of operations.

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

Asset Acquisitions

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 following table presents the cumulative adjusted purchase price of transactions accounted for as asset acquisitions, by basin, included in oil and gas properties on the Company’s consolidated balance sheets:

(in thousands)	Year Ended December 31, 2024		Year Ended December 31, 2023	
Permian		46,494		24,534
Eagle Ford		—		2,800
Bakken		1,981		—
Haynesville		—		2,921
DJ		5,325		16,620
Appalachian		10,357		—
Total	$	64,157	$	46,875

Business Combinations

There were no acquisitions accounted for under the acquisition method of accounting as a business combination in accordance with ASC Topic 805, *Business Combinations* ("ASC 805") during 2024.

During 2023, the Company closed on three separate acquisitions that were accounted for as business combinations in accordance with ASC Topic 805. 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 for the year ended December 31, 2023:

(in thousands)		
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) Amount includes asset retirement costs of $0.3 million.

Divestitures

During the year ended December 31, 2024, the Company sold certain oil and gas properties in exchange for total consideration of $14.9 million. The Company recorded a gain of $0.5 million on the disposal of unproved oil and natural gas properties, which is included in other, net in the consolidated statement of operations for the year ended December 31, 2024.

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.

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, 2024, 2023 and 2022:

	Year Ended December 31,		
(in thousands)	**2024**	**2023**	**2022**
Asset retirement obligations, beginning of year	$ 9,874	$ 4,963	$ 2,962
Liabilities incurred during the period	760	2,370	1,012
Revision of estimates(1)	—	2,596	490
Accretion of discount during the period	791	441	499
Disposals or settlements	(504)	(496)	—
Asset retirement obligations, end of year	$ 10,921	$ 9,874	$ 4,963
Less current portion of asset retirement obligations	228	483	218
Asset retirement obligations, long-term	$ 10,693	$ 9,391	$ 4,745

(1) Revisions in estimated liabilities during 2023 relate primarily to changes in estimated well lives, while revisions in 2022 relate primarily to changes in estimates of asset retirement costs.

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. 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.

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

	Year Ended December 31,		
(in thousands)	2024	2023	2022
Current			
Federal	$ —	$ —	$ —
State	249	209	—
	249	209	—
Deferred			
Federal	$ 6,449	$ 22,314	$ 11,444
State	(491)	1,960	1,406
	5,958	24,274	12,850
Income tax expense	$ 6,207	$ 24,483	$ 12,850

The Company's effective tax rate was 24.9%, 23.2% and 4.7% for the years ended December 31, 2024, 2023 and 2022, respectively. For 2024, the effective tax rate differs from the enacted statutory rate of 21% primarily due to the impact of certain discrete items, state income taxes and changes in state tax rates. For 2023, the effective tax rate differed from the enacted statutory rate of 21% primarily due to the impact of certain discrete items and 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:

	Year Ended December 31,		
(in thousands)	2024	2023	2022
Income before income taxes	$ 24,966	$ 105,582	$ 275,194
Income tax expense at federal statutory rate	5,243	22,172	57,791
Net (income) loss prior to Business Combination - non-taxable	—	—	(46,051)
Impact of prior tax returns	1,487	142	—
State income taxes, net of federal benefit	524	2,169	1,110
Impact of tax rate and apportionment updates	(1,047)	—	—
Income tax expense	$ 6,207	$ 24,483	$ 12,850
Effective tax rate	24.9 %	23.2 %	4.7 %

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

	Year Ended December 31,	
(in thousands)	2024	2023
Deferred tax assets		
Net operating loss carryforwards	$ 14,152	$ 13,677
Disallowed interest expense carryforward	5,410	1,335
Asset retirement obligations	2,459	2,169
Unrealized derivatives	1,118	—
Unrealized loss on investment	3,327	—
Other deductible temporary differences	831	495
Total deferred tax assets	27,297	17,676
Less: valuation allowance	—	—
Net deferred tax assets	$ 27,297	$ 17,676
Deferred tax liabilities		
Property, plant and equipment	$ (107,243)	$ (88,870)
Unrealized derivatives	—	(2,795)
Total deferred tax liabilities	(107,243)	(91,665)
Net deferred tax liability	$ (79,946)	$ (73,989)

As of December 31, 2024, the Company had accumulated federal net operating loss carryforwards of $63.7 million, none of which are expected to expire, and state net operating loss carryforwards of approximately $63.7 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, 2024, 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, 2024, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes for tax years 2020 through 2024 and state income taxes for tax years 2019 through 2024.

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, 2024 and 2023, 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 or 2024 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 future periods but will continue to monitor.

8. Debt

The carrying value of the Company’s total debt was $205.0 million and $110.0 million as of December 31, 2024 and 2023, respectively.

Granite Ridge Credit Agreement

On October 24, 2022, Granite Ridge entered into a senior secured revolving credit agreement (as amended, the “Credit Agreement”) with a syndicate of banks, currently led by Bank of America, N.A., as administrative agent. The Credit Agreement has a maturity date of five years from the effective date thereof, or October 24, 2027.

The borrowing base is 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 April 1, 2024, the Company entered into the Resignation, Appointment, Assignment and Third Amendment to Credit Agreement (the “Third Amendment”) which, among other things, (a) appointed a new administrative agent and L/C Issuer (as defined therein) (b) increased the size of the lender group by adding nine new banks, with one bank exiting the facility, (c) increased the borrowing base from $275.0 million to $300.0 million, and (d) increased the aggregate elected commitments from $240.0 million to $300.0 million. In connection with the Third Amendment and the increase in the size of the lender group, certain lenders decreased their commitment amounts and one bank exited the facility, which resulted in a write-off of $2.2 million in deferred financing costs that were previously capitalized in other long-term assets in the consolidated balance sheets. This $2.2 million is included in interest expense in the consolidated statement of operations for the year ended December 31, 2024 and is added back as a non-cash adjustment to operating activities in the consolidated statement of cash flows. The Company capitalized approximately $3.0 million in expenses related to the Third Amendment that are included in other long-term assets in the consolidated balance sheet.

On November 1, 2024, the Company and its lenders entered into the Fourth Amendment to the Credit Agreement, which amended the Credit Agreement to, among other things, (a) increase the borrowing base from $300.0 million to $325.0 million, and (b) increase the aggregate elected commitments from $300.0 million to $325.0 million.

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 the Company 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.

Deferred financing costs were $4.3 million at December 31, 2024, and these costs are being amortized over the term of the Credit Agreement. At December 31, 2024, the Company had outstanding borrowings of $205.0 million and $0.3 million of letters of credit issued and outstanding under the Credit Agreement, resulting in availability of $119.7 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. SOFR loans 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 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 Company's weighted average effective interest rate under the Credit Agreement as of December 31, 2024 and 2023 was 8.12% and 8.71%, respectively.

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, 2024, 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 the year ended December 31, 2023.

Common stock dividends - The Company paid dividends of $57.5 million, or $0.44 per share, and $58.6 million, or $0.44 per share, during the years ended December 31, 2024 and 2023, 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 year ended December 31, 2023, the Company repurchased 5,651,707 shares under the program at an aggregate cost of $36.1 million. 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 provides 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 pays the Manager an annual services fee of $10.0 million and reimburses 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 of the Company). 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, 2024, 2023 and 2022, service fees for the Company under the MSA were approximately $10.0 million, $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 year ended December 31, 2022, total management fees for the Company were $7.9 million and are included in general and administrative expenses within the accompanying consolidated statements of operations.

During the year ended December 31, 2024, the Company divested of partial interests in certain unproved oil and natural gas properties to an affiliate of the Manager for consideration of $7.5 million. No gain or loss was recognized on the sale.

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, 2024, 2023 and 2022.

Major Operators	2024	2023	2022
Operator A	*	11 %	12 %
Operator B	*	12 %	10 %
Operator C	*	*	10 %
Operator D	14 %	*	*

* 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, 2024, 2023, or 2022. 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 International Swap Dealers Association Master Agreements ("ISDAs") entered into with parties that are also lenders under the Company's Credit Agreement. The Company's obligations under the derivative instruments are secured pursuant to the Credit Agreement, and no additional collateral has been posted by the Company.

13. Stock Incentive Plan

The Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan (the "Plan") 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. As of December 31, 2024, the Company had 5.0 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.

Stock-based compensation expense is recognized net of forfeitures within general and administrative expenses on the consolidated statements of operations. The Company has elected to account for forfeitures of stock-based compensation awards as they occur in determining compensation expense. The stock-based compensation expense is presented below for the indicated periods:

	Year Ended December 31,	
(in thousands)	2024	2023
Stock-based compensation expense		
Restricted Stock Awards	$ 1,872	$ 1,081
Performance Stock Units	210	47
Stock Options	216	234
Other Awards	—	800
Total stock-based compensation expense	$ 2,298	$ 2,162

There was no stock-based compensation expense for the year ended December 31, 2022.

Restricted Stock Awards - The Company grants service-based restricted stock awards to certain of its employees and consultants, which vest ratably over a period of three years, and to non-employee directors, which vest in full after one year. 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 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, 2024 is presented below.

	Restricted Stock Awards	Weighted Average Grant Date Fair Value Per Share
Outstanding at December 31, 2023	295,990	$ 5.75
Awards granted	383,430	$ 6.07
Awards canceled/forfeited	(6,530)	$ 5.74
Awards vested	(154,842)	$ 6.47
Outstanding at December 31, 2024	518,048	$ 5.77

The aggregate fair value of restricted stock awards that vested during the year ended December 31, 2024 was $1.0 million.

PSUs - The Company has granted PSUs to certain of its officers under the Plan. The PSUs cliff vest at the end of three years, 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 officer's 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 based on market performance, while PSUs based on financial performance are valued using the closing price of the Company's common stock on the date of grant.

A summary of the Company's PSU activity for the year ended December 31, 2024 is presented below.

	Performance Stock Units	Weighted Average Grant Date Fair Value Per Share
Outstanding at December 31, 2023	26,574	$ 6.01
Awards granted	70,958	$ 7.51
Outstanding at December 31, 2024	97,532	$ 7.10

Stock Options - The Company has granted stock options to certain of its officers under the Plan. The Company’s outstanding stock options expire 10 years following the date of grant. Pursuant to the stock options granted under the Plan, 33% of the options vest 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. A summary of the Company's stock option activity for the year ended December 31, 2024 is presented below.

	Stock Options	Weighted Average Exercise Price Per Share	Aggregate intrinsic value
			(in thousands)
Outstanding at December 31, 2023	392,108	$ 8.45	
Options granted	134,375	$ 6.06	
Options canceled/forfeited	—	$ —	
Options exercised	—	$ —	
Outstanding at December 31, 2024	526,483	$ 7.84	$ 158
Options exercisable at December 31, 2024	306,195	$ 8.10	$ 87

The fair value of each stock option award is estimated on the date of grant. For stock options granted at-the-money, grant date fair value is 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 higher than the stock price at the date of grant, grant date fair value is estimated using a lattice-based option valuation model that incorporates 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, 2024 was $1.38 per share. The weighted average remaining terms on the outstanding options and the exercisable options was 8.51 years and 8.4 years, respectively. The Company used the following assumptions to estimate the fair value of stock options granted during the year ended December 31, 2024:

Risk-free interest rate	4.0%
Volatility	44.0%
Expected term	5.53 years
Dividend yield	7.3%

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, 2024:

(in thousands)	Restricted Stock Awards	Performance Stock Units	Stock Options
2025	$ 748	$ 245	$ 54
2026	269	186	6
2027	34	—	—
Total	$ 1,051	$ 431	$ 60

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

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The following table presents the basic and diluted earnings per share computations for the years ended December 31, 2024, 2023 and 2022:

	Year Ended December 31,		
(in thousands)	2024	2023	2022
Net income	$ 18,759	$ 81,099	$ 262,344
Participating basic earnings (a)	(211)	(152)	—
Basic earnings attributable to common stockholders	18,548	80,947	262,344
Reallocation of participating earnings	—	—	—
Diluted earnings attributable to common stockholders	$ 18,548	$ 80,947	$ 262,344
Weighted average common shares outstanding:			
Weighted average common shares outstanding – basic	130,189	133,093	132,923
Dilutive performance stock units	29	10	—
Dilutive stock options	9	6	—
Vesting Shares	—	—	151
Weighted average common shares outstanding – diluted	130,227	133,109	133,074
Net income per common share:			
Basic	$ 0.14	$ 0.61	$ 1.97
Diluted	$ 0.14	$ 0.61	$ 1.97

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends with the common stockholders 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.

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,		
	2024	2023	2022
Number of antidilutive common shares:			
Antidilutive performance stock units	44,649	23,428	—
Antidilutive stock options	491,745	303,805	—
Total antidilutive common shares	536,394	327,233	—

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15. Accounts Payable and Accrued Liabilities

The following table provides the components of the Company’s accounts payable and accrued liabilities at December 31, 2024 and December 31, 2023:

	December 31,	
(in thousands)	2024	2023
Accounts payable and accrued liabilities:		
Accrued drilling costs	$ 62,346	$ 32,739
Accounts and JIB payable	26,438	20,037
Accrued production costs	7,646	5,729
Other	3,010	2,370
Total accounts payable and accrued liabilities	$ 99,440	$ 60,875

16. Subsequent Events

Dividend

On February 14, 2025, the Company's Board of Directors declared a cash dividend of $0.11 per share for the first quarter of 2025. The dividend will be paid on March 14, 2025 to stockholders of record as of February 28, 2025.

Acquisitions

As of March 4, 2025, the Company closed on various acquisitions of oil and gas properties during 2025 for a total purchase price of $26.0 million, of which $19.7 million were acquisition of properties in the Permian Basin. The Company is evaluating the accounting treatment of these transactions.

New Commodity Derivative Contracts

Subsequent to December 31, 2024, the Company entered into the following oil and natural gas derivative contracts to hedge additional amounts of estimated future production.

	2025					2026
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	Total
Collars (oil)						
Volume (Bbl)	233,000	310,000	280,000	204,000	1,027,000	1,316,000
Weighted-average floor price ($/Bbl)	$ 69.84	$ 67.49	$ 65.29	$ 62.47	$ 66.43	$ 60.00
Weighted-average ceiling price ($/Bbl)	$ 75.70	$ 74.41	$ 74.01	$ 74.41	$ 74.59	$ 70.90
Collars (natural gas)						
Volume (Mcf)	—	—	—	888,000	888,000	1,752,000
Weighted-average floor price ($/Mcf)	$ —	$ —	$ —	$ 4.10	$ 4.10	$ 4.06
Weighted-average ceiling price ($/Mcf)	$ —	$ —	$ —	$ 4.98	$ 4.98	$ 4.89
Swaps (natural gas)						
Volume (Mcf)	1,234,000	1,843,000	1,571,000	498,000	5,146,000	2,388,000
Weighted-average price ($/Mcf)	$ 3.78	$ 3.79	$ 3.79	$ 3.79	$ 3.79	$ 3.76

Capitalized Costs

(in thousands)	December 31, 2024	December 31, 2023
Oil and natural gas properties:		
Proved	$ 1,484,968	$ 1,198,845
Unproved	55,053	37,838
Less: accumulated depletion	(643,051)	(467,141)
Net capitalized costs for oil and natural gas properties	$ 896,970	$ 769,542

Costs Incurred for Oil and Natural Gas Producing Activities

(in thousands)	December 31, 2024	2023	2022
Property acquisition costs:			
Proved	$ 3,436	$ 36,824	$ 26,219
Unproved	60,721	42,225	22,973
Development costs	290,283	283,915	256,664
Total costs incurred for oil and natural gas properties	$ 354,440	$ 362,964	$ 305,856

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, 2024	2023	2022
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	$ 76.32	$ 78.21	$ 94.14
Natural gas per Mcf	$ 2.13	$ 2.64	$ 6.36

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 emphasizes that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of 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, 2021	22,818	125,347	43,710
Revisions of previous estimates	(456)	6,225	581
Extensions and discoveries	3,690	27,126	8,211
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
Revisions of previous estimates	(1,992)	(1,860)	(2,302)
Extensions and discoveries	3,545	20,043	6,885
Divestiture of reserves	(1,718)	(10,840)	(3,525)
Acquisition of reserves	5,518	20,442	8,925
Production	(4,483)	(27,944)	(9,140)
Proved developed and undeveloped reserves at December 31, 2024	28,187	156,769	54,315

	Oil (MBbl)	Natural Gas (MMcf)	MBoe
Proved developed reserves:			
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
December 31, 2024	19,269	118,103	38,953
Proved undeveloped reserves:			
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
December 31, 2024	8,918	38,666	15,362

Notable changes in proved reserves for the year ended December 31, 2024 included the following:

- *Revisions of previous estimates.* In 2024, revisions of previous estimates decreased proved developed and undeveloped reserves by approximately 2,302 MBoe. The decrease was driven in part by lower oil and natural gas prices. The Company's proved reserves at December 31, 2024 were determined using the SEC prices of $76.32 per Bbl of oil and $2.13 per MMBtu of natural gas, as compared to corresponding prices of $78.21 per Bbl of oil and $2.64 per MMBtu of natural gas at December 31, 2023. In addition to price revisions, there were negative revisions of 2,013 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 2024, total extensions and discoveries of 6,885 MBoe were primarily attributable to successful drilling in the Permian Basin, which added 5,760 MBoe. Proved developed reserves increased approximately 2,120 MBoe due to the Company's drilling activity in 2024, and 4,765 MBoe as a result of new proved undeveloped locations added.

- *Divestiture of reserves.* In 2024, the Company divested 3,525 MBoe of proved reserves primarily in the Permian Basin (see Note 5).

- *Acquisitions of reserves.* In 2024, total acquisitions of reserves of 8,925 MBoe were attributable to the acquisitions of oil and natural gas properties primarily in the Permian Basin. The Permian Basin accounted for 7,233 MBoe of acquisitions during 2024. See Note 5 for additional discussion regarding acquisitions.

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.

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 reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are included for reserves for which there is a high degree of confidence in their recoverability and they are scheduled to be drilled within the next five years.

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 the periods indicated:

	December 31,		
(in thousands)	2024	2023	2022
Future cash inflows	$ 2,425,248	$ 2,589,302	$ 3,572,271
Future production costs	(809,466)	(791,705)	(755,059)
Future development costs	(277,341)	(366,751)	(249,659)
Future income tax expense	(192,593)	(226,732)	(484,348)
Future net cash flows	1,145,848	1,204,114	2,083,205
10% discount for estimated timing of cash flows	(424,880)	(482,206)	(817,278)
Standardized measure of discounted future net cash flows	$ 720,968	$ 721,908	$ 1,265,927

GRANITE RIDGE RESOURCES, INC.
Unaudited Supplementary Information

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

	December 31,		
(in thousands)	2024	2023	2022
Balance, beginning of period	$ 721,908	$ 1,265,927	$ 774,351
Sales of oil and natural gas produced, net of production costs	(296,562)	(305,843)	(422,120)
Extensions and discoveries	96,196	157,605	239,173
Previously estimated development cost incurred during the period	106,117	98,461	93,895
Net change of prices and production costs	(131,694)	(691,751)	671,556
Change in future development costs	16,705	6,284	(6,186)
Revisions of quantity and timing estimates	(7,561)	(204,963)	44,022
Accretion of discount	85,643	155,912	77,823
Change in income taxes	13,559	158,677	(289,317)
Acquisition of reserves	157,044	135,526	154,300
Divestiture of reserves	(36,769)	(77,402)	—
Other	(3,618)	23,475	(71,570)
Balance, end of period	$ 720,968	$ 721,908	$ 1,265,927

GRANITE RIDGE RESOURCES, INC.
2022 OMNIBUS INCENTIVE PLAN

RESTRICTED STOCK AWARD

Granite Ridge Resources, Inc. (the "***Company***") hereby grants the following Restricted Stock Award pursuant to its 2022 Omnibus Incentive Plan (the "***Plan***"). The terms of the grant are set forth in the attached Restricted Stock Award Agreement (the "***Agreement***").

NOTICE OF GRANT

Participant: [____]

Date of Grant: [____]

Number of Shares of Restricted Stock: [____]

Vesting: 1/3 on 1st anniversary of Date of Grant
1/3 on 2nd anniversary of Date of Grant
1/3 on 3rd anniversary of Date of Grant

All vesting is dependent on the Participant continuing to be employed by, or provide services to, the Company, as provided herein, through the relevant vesting date, unless otherwise specified in the Agreement.

The above is a summary description of certain provisions of the Agreement and is not intended to be complete. In the event any aspect of this summary conflicts with the terms of the Agreement, the terms of the Agreement shall govern.

Granite Ridge Resources, Inc.

By:__________
Title:__________

I hereby accept the Restricted Stock Award described in the Agreement, and I agree to be bound by the terms of the Plan and the Agreement. I hereby further agree that all the decisions and determinations of the Committee shall be final and binding.

Participant:___________

Date:_____________

GRANITE RIDGE RESOURCES, INC.

2022 OMNIBUS INCENTIVE PLAN

RESTRICTED STOCK AWARD AGREEMENT

This **RESTRICTED STOCK AWARD AGREEMENT** (the "***Agreement***"), dated as of date set forth on the Notice of Grant attached hereto (the "***Date of Grant***"), is delivered by Granite Ridge Resources, Inc. (the "***Company***") to the individual named on the Notice of Grant attached hereto (the "***Participant***").

RECITALS

A. The Granite Ridge Resources, Inc. 2022 Omnibus Incentive Plan (the "***Plan***") provides for the grant of stock and stock-based awards with respect to shares of Common Stock of the Company, in accordance with the terms and conditions of the Plan. The Company has decided to make a restricted stock award as an inducement for the Participant to promote the best interests of the Company and its stockholders.

B. The terms and conditions of the award of Restricted Stock should be construed and interpreted in accordance with the terms and conditions of this Agreement and the Plan. Any term capitalized herein but not defined shall have the same meaning as set forth in the Plan. For purposes of this Agreement, "Company" shall mean the Company and any of its Subsidiaries where applicable.

NOW, THEREFORE, the parties to this Agreement, intending to be legally bound hereby, agree as follows:

1. **Grant of Restricted Stock Award**. As of the Grant Date, the Company hereby grants to the Participant an award of the number of shares of Restricted Stock as set forth on the Notice of Grant attached hereto (the "***Restricted Stock***"), on the terms and conditions hereinafter provided.

2. **Vesting of Restricted Stock.**

(a) The Restricted Stock shall vest if the Participant continues to be employed by, or provide service to, the Company from the Date of Grant until the applicable vesting date (the "***Vesting Date***") set forth on the Notice of Grant attached hereto. If the vesting schedule would produce fractional shares, the number of shares of Restricted Stock that vest on the applicable Vesting Date shall be rounded down to the nearest share.

(b) In the event the Participant ceases employment with the Company as a result of death or Disability, all unvested Restricted Stock shall become fully vested as of the termination date. Except as set forth herein, in the event the Participant's employment with the Company terminates for any other reason, the Participant shall forfeit the unvested Restricted Stock as of the Participant's termination date.

(c) In the event the Company experiences a Change of Control, and the Participant is terminated by the Company or the surviving or successor entity without Cause within twelve (12) months following the Change of Control, all unvested Restricted Stock subject to this Agreement shall vest as of the termination date.

(d) For the purposes of this Agreement, "***Disability***" shall mean any physical or mental impairment which qualifies the Participant for disability benefits under the applicable long-term disability plan maintained by the Company or, if no such plan applies, which would qualify the Participant for disability benefits under the Federal Social Security System.

(e) For the purposes of this Agreement, "***Cause***" shall mean any event which constitutes Cause as defined in the employment agreement, offer letter or other arrangement between the Company and the Participant, or, if no such definition exists, the occurrence of any of the following: (i) the Participant's convicted of, or pled guilty or nolo contendere to, a felony or crime involving moral turpitude; (ii) the willful and continued failure by the Participant to substantially perform his or her duties and obligations to the Company (other than any such failure resulting from any physical or mental condition, whether or not such condition constitutes a Disability); (iii) the willful engaging by the Participant in misconduct that is materially injurious to the Company, monetarily or otherwise; or (iv) the Participant's breach of any written confidentiality, noncompetition or nonsolicitation agreement between the Participant and the Company.

3. **Non-Transferability**. The Restricted Stock may not, prior to vesting, be assigned, alienated, attached, sold or transferred, pledged or otherwise disposed or encumbered by the Participant, other than by will or by the laws of descent and distribution. Any attempt to assign, transfer, pledge or otherwise dispose of the Restricted Stock contrary to the provisions hereof, and the levy of any execution, attachment or similar process upon the Restricted Stock award, shall be null, void and without effect; *provided*, *however,* that the designation of a beneficiary shall not constitute an assignment, alienation, pledge, attachment, sale, transfer or encumbrance. The Participant may designate a beneficiary, on a form supplied by the Committee, who may possess all rights with respect to the Restricted Stock award in the event of the Participant's death. No such permitted transfer of the Restricted Stock award to heirs or legatees of the Participant shall be effective to bind the Company unless the Committee shall have been furnished with written notice thereof and a copy of such evidence as the Committee may deem necessary to establish the validity of the transfer and the acceptance by the transferee or transferees of the terms and conditions hereof.

4. **Delivery of Restricted Stock**.

(a) Book Entry Form. The Company shall issue the Restricted Stock subject to the award either: (i) in certificate form as provided in Section 4(b) below; or (ii) in book entry form, registered in the name of the Participant with notations regarding the applicable restrictions on transfer imposed under this Agreement.

(b) Certificates to be Held by Company; Legend. Any certificates representing the shares of Restricted Stock that may be delivered to the Participant by the Company prior to vesting shall be redelivered to the Company to be held by the Company until the restrictions on such shares shall have lapsed and the shares shall thereby have become vested or the shares represented thereby have been forfeited hereunder. Such certificates shall bear the following legend and any other legends the Company may determine to be necessary or advisable to comply with all applicable laws, rules, and regulations:

> "The ownership of this certificate and the shares of stock evidenced hereby and any interest therein are subject to substantial restrictions on transfer under an Agreement entered into between the registered owner and Granite Ridge Resources, Inc. A copy of such Agreement is on file in the office of the Secretary of Granite Ridge Resources, Inc."

(c) Delivery of Shares Upon Vesting. Promptly after the vesting of any shares of Restricted Stock pursuant to Section 2 hereof, the Company shall, as applicable, either remove the notations on any shares of Restricted Stock issued in book entry form which have vested or deliver to the Participant a certificate or certificates evidencing the number of shares of Restricted Stock which have vested. The Participant (or the beneficiary or personal representative of the Participant in the event of the Participant's death or disability, as the case may be) shall deliver to the Company any representations or other documents or assurances as the Company or its counsel may determine to be necessary or advisable in order to ensure compliance with all applicable laws, rules, and regulations with respect to the grant of the Restricted Stock award and the delivery of shares in respect thereof. The shares so delivered shall no longer be shares of Restricted Stock hereunder.

5. **Securities Laws**. Upon the issuance, vesting or delivery of any shares related to the Restricted Stock award, the Participant will make or enter into such written representations, warranties and agreements as the Company may reasonably request in order to comply with applicable securities laws or with this Agreement.

6. **Rights as a Stockholder**. Prior to the Vesting Date, the Participant shall not have the right to vote shares of Common Stock subject to the Restricted Stock but shall receive any dividends or other distributions paid on such shares of Common Stock.

7. **Withholding**. The Company shall be entitled to require a cash payment by or on behalf of the Participant and/or to deduct from other compensation payable to the Participant any sums required by federal, state or local tax law to be withheld with respect to the vesting of any Restricted Stock. Alternatively, the Participant or other person in whom the Restricted Stock vests may irrevocably elect, in such manner and at such time or times prior to any applicable tax date as may be permitted or required under Section 15 of the Plan and rules established by the Administrator, to have the Company withhold and reacquire shares of Restricted Stock at their fair market value at the time of vesting to satisfy any withholding obligations of the Company with respect to such vesting; provided, however, that the number of such shares of Common Stock so withheld shall not exceed the amount necessary to satisfy the Company's required tax withholding obligations up to the maximum statutory withholding rates for federal, state, local and foreign tax purposes, including payroll taxes, that are applicable to supplemental taxable

income. Any election to have shares so held back and reacquired shall be subject to such rules and procedures, which may include prior approval of the Committee, as the Committee may impose, and shall not be available if the Participant makes or has made an election pursuant to Section 83(b) of the Code with respect to such Award.

8. **Adjustments; Change of Control**. The provisions of the Plan applicable to adjustments (as described in Section 10 of the Plan) or other corporate transaction, including a Change of Control (as described in Section 11 of the Plan), shall apply to the Restricted Stock..

9. **Grant Subject to Plan Provisions**. This grant is made pursuant to the Plan, the terms of which are incorporated herein by reference, and in all respects shall be interpreted in accordance with the Plan. The award of Restricted Stock is subject to interpretations, regulations and determinations concerning the Plan established from time to time by the Committee in accordance with the provisions of the Plan. The Committee shall have the authority to interpret and construe the award of Restricted Stock pursuant to the terms of the Plan, and its decisions shall be conclusive as to any questions arising hereunder.

10. **No Employment or Other Rights**. The grant of the Restricted Stock shall not confer upon the Participant any right to be retained by or in the employ or service of the Company and shall not interfere in any way with the right of the Company to terminate the Participant’s employment or service at any time. The right of the Company (or any of its Subsidiaries) to terminate at will the Participant’s employment or service at any time for any reason is specifically reserved.

11. **Clawback**. In accepting the grant of Restricted Stock, the Participant agrees to be bound by any clawback policy that the Company may currently have in place or may adopt in the future in order to comply with applicable law or stock exchange rules.

12. **Successors**. The rights and protections of the Company hereunder shall extend to any successors or assigns of the Company and to the Company’s parents, Subsidiaries, and affiliates. This Agreement may be assigned by the Company without the Participant’s consent.

13. **Applicable Law**. The validity, construction, interpretation and effect of this Agreement shall be governed by and construed in accordance with the laws of the State of Delaware, without giving effect to the conflict of laws provisions thereof.

14. **Notice**. Any notice to the Company provided for in this Agreement shall be addressed to the Company in care of the Committee, and any notice to the Participant shall be addressed to such Participant at the current address shown on the payroll of the Company, or to such other address as the Participant may designate to the Company in writing. Any notice shall be delivered by hand, sent by telecopy or enclosed in a properly sealed envelope addressed as stated above, deposited, postage prepaid, in a post office regularly maintained by the United States Postal Service.

15. **Counterparts**. This Agreement may be executed in one or more counterparts, each of which will be deemed to be an original copy of this Agreement and all of which, when taken

together, will be deemed to constitute one and the same agreement. Facsimile or other electronic transmission of any signed original document or retransmission of any signed facsimile or other electronic transmission will be deemed the same as delivery of an original.

16. **Complete Agreement**. Except as otherwise provided for herein, this Agreement and those agreements and documents expressly referred to herein embody the complete agreement and understanding among the parties and supersede and preempt any prior understandings, agreements or representations by or among the parties, written or oral, which may have related to the subject matter hereof in any way. The terms of this Agreement shall be binding upon the executors, administrators, heirs, successors and assigns of the Participant.

17. **Committee Authority**. By entering into this Agreement the Participant agrees and acknowledges that all decisions and determinations of the Committee shall be final and binding on the Participant, his or her beneficiaries and any other person having or claiming an interest in the Restricted Stock award.

Exhibit 19.1

GRANITE RIDGE

GRANITE RIDGE RESOURCES, INC.
INSIDER TRADING POLICY
(Adopted as of August 9, 2023)

This Insider Trading Policy (this "**Policy**") provides guidelines to directors, officers, employees, and consultants of Granite Ridge Resources, Inc. (the "**Company**"), with respect to transactions in the Company's securities (including its common stock as well as options to buy or sell Company securities, warrants, and convertible securities) and derivative securities relating to the Company's securities, whether or not issued by the Company (such as exchange-traded options) for the purpose of promoting compliance with applicable securities laws.

This Policy applies to directors, officers, employees, and consultants of the Company (including all employees of Grey Rock Administration, LLC ("**Grey Rock**") that provide services to the Company pursuant to that certain Management Services Agreement, by and between Grey Rock and the Company (the "**Grey Rock Employees**")) who receive or are aware of Material, Non-Public Information (as defined below) regarding (1) the Company and (2) any other company with publicly-traded securities, including the Company's customers, joint-venture or strategic partners, vendors, and suppliers ("**business partners**"), obtained in the course of employment by, or in association or consultation with, the Company. This Policy also applies to any person who receives Material, Non-Public Information from an insider. The people to whom this Policy applies are referred to in this Policy as "insiders." All insiders must comply strictly with this Policy.

The Company reserves the right to amend or rescind this Policy or any portion of it at any time and to adopt different policies and procedures at any time. In the event of any conflict or inconsistency between this Policy and any other materials distributed by the Company, this Policy shall govern. If a law conflicts with this Policy, you must comply with the law.

You should read this Policy carefully, ask the Company's Corporate Secretary or such other officer designated by the Board to oversee this Policy (as applicable, the "**Compliance Officer**") any questions regarding this Policy, and promptly sign and return the certification attached as Annex A acknowledging receipt of this Policy to:

Granite Ridge Resources, Inc.
5217 McKinney Avenue, Suite 400
Dallas, Texas 75205
Attention: Compliance Officer

The Company's Compliance Officer is responsible for ensuring that all of the Company's directors, officers, other employees, and Grey Rock Employees promptly sign and return the attached certification acknowledging receipt of this Policy.

I. Definitions and Explanations

A. *Material, Non-Public Information*

1. What Information is "Material"?

It is not possible to define all categories of Material information. However, information should be regarded as Material if there is a substantial likelihood that it would be considered important to an investor in making an investment decision regarding the purchase or sale of the Company's securities. Information that is likely to affect the price of a company's securities (whether positive or negative) is almost always Material. It is also important to remember that Material information can be positive or negative and can relate to virtually any aspect of a company's business or to any type of security, debt, or equity.

While it may be difficult under this standard to determine whether particular information is Material, there are various categories of information that are particularly sensitive and, as a general rule, should always be considered material information. Common examples of Material information include:

- Unpublished financial results (annual, quarterly, or otherwise);
- Unpublished projections of future earnings or losses;
- News of a pending or proposed merger;
- News of a significant acquisition or a sale of significant assets;
- News of a significant development or discovery with respect to the Company's oil and gas assets;
- Impending announcements of bankruptcy or financial liquidity problems;
- Gain or loss of a substantial business partner;
- Changes in the Company's distribution or dividend policy;
- Stock splits;
- Changes in the Company's or its subsidiaries' credit ratings;
- New equity or debt offerings;
- Significant cybersecurity incidents;

- Significant developments in litigation or regulatory proceedings; and

- Changes in management.

The above list is for illustration purposes only. If securities transactions become the subject of scrutiny, they will be viewed after-the-fact and with the benefit of hindsight.[1] Therefore, before engaging in any securities transaction, you should consider carefully how the Securities and Exchange Commission ("**SEC**") and others might view your transaction in hindsight and with all of the facts disclosed. A good general rule of thumb: When in doubt, do not trade.

2. What Information is "Non-Public"?

Information is "Non-Public" if it has not been previously disclosed to the general public and is otherwise not generally available to the investing public. In order for information to be considered public, it must be widely disseminated in a manner making it generally available to investors through such media as Dow Jones, Business Wire, Reuters, The Wall Street Journal, Associated Press, a broadcast on widely available radio or television programs, publication in a widely available newspaper, magazine, or news web site, a Regulation FD-compliant conference call, or public disclosure documents filed with the SEC that are available on the SEC's web site. The circulation of rumors, even if accurate and reported in the media, does not constitute effective public dissemination. Generally, one should allow two full Trading Days following publication as a reasonable waiting period before information is deemed to be public.

B. *Related Person*

"***Related Person***" means, with respect to the Company's insiders:

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[1] Determining what is, or what may be viewed in hindsight as, material is a matter of judgment guided principally by case law (discussed immediately below), SEC enforcement actions, the definition of "material" found in Rule 405 of the Securities Act of 1933, as amended, the quantitative and qualitative analysis of materiality outlined in SEC Staff Accounting Bulletin 99: Materiality ("SAB 99"), and even line items of disclosure documents. While a court's determination of "materiality" depends largely on facts and circumstances, case law suggests that the following are among the items a court may consider in determining whether there was a substantial likelihood that a reasonable investor would consider the information important: (a) with respect to projections, the balance between probability of the event occurring and magnitude of the event; (b) an initial numerical threshold, such as 5%, as well as the qualitative factors for materiality outlined in SAB 99; (c) a combination of the total mix of information available, actual market reaction to the information (or assumed market reaction if the information was never made public), and reactions to the information by other insiders; and (d) the timing and magnitude of a person's trades as well as whether or not such trades were consistent with the person's prior trading history.

- Any family member living in the insider's household (including a spouse, minor child, minor stepchild, parent, stepparent, grandparent, sibling, in-law) and anyone else living in the insider's household;
- Family members who do not live in the insider's household but whose transactions in Company securities are directed by the insider or subject to the insider's influence or control;
- Partnerships in which the insider is a general partner;
- Trusts of which the insider is a trustee;
- Estates of which the insider is an executor; and
- Other equivalent legal entities that such insider controls.

C. *Trading Day*

"**Trading Day**" means a day on which national stock exchanges or the Over-The-Counter Bulletin Board Quotation System are open for trading, and a "**Trading Day**" begins at the time trading begins.

II. General Policy

This Policy prohibits insiders from trading or "tipping" others who may trade in the Company's securities while aware of Material, Non-Public Information about the Company. Insiders are also prohibited from trading or tipping others who may trade in the securities of another company if they learn Material, Non-Public Information about the other company in connection with their employment by, or relationship with, the Company. These illegal activities are commonly referred to as "insider trading."

All insiders should treat Material, Non-Public Information about the Company's business partners with the same care required with respect to Material, Non-Public Information related directly to the Company.

A. *Trading on Material, Non-Public Information*

Except as otherwise specified in this Policy, no insider or Related Person shall engage in any transaction involving a purchase or sale of the Company's securities, including any offer to purchase or offer to sell, during any period commencing with the date that he or she is aware of Material, Non-Public Information concerning the Company and ending at the beginning of the third Trading Day following the date of public disclosure of the Material, Non-Public Information, or at the time that the information is no longer Material.

B. *Tipping Others of Material, Non-Public Information*

No insider shall disclose or tip Material, Non-Public Information to any other person (including Related Persons) where the Material, Non-Public Information may be used by that person to his or her profit by trading in the securities of the company to which the Material, Non-Public Information relates, nor shall the insider or the Related Person make recommendations or express opinions on the basis of Material, Non-Public Information as to trading in such company's securities. Insiders are not authorized to recommend the purchase or sale of the Company's securities to any other person regardless of whether the insider is aware of Material, Non-Public Information.

C. *Confidentiality of Material, Non-Public Information*

Material, Non-Public Information relating to the Company or its business partners is the Company's property and the unauthorized disclosure of Material, Non-Public Information is prohibited. If an insider receives any inquiry from outside the Company (such as a securities analyst) for information (particularly financial results and/or projections) that may be Material, Non-Public Information, the inquiry should be referred to the Company's Compliance Officer, who is responsible for coordinating and overseeing the release of that information to the investing public, securities analysts, and others in compliance with applicable laws and regulations.

D. *Special and Prohibited Transactions*

Because the Company believes it is improper and inappropriate for its insiders to engage in short-term or speculative transactions involving certain securities, it is the Company's policy that its insiders may not engage in any of the transactions specified below.

1. *Transactions in Company Debt Securities*. The Company believes that it is inappropriate for its insiders to be creditors of the Company due to actual or perceived conflicts of interest that may arise in connection therewith. Therefore, transactions in Company debt securities, whether or not those securities are convertible into Company common stock, are prohibited by this Policy.

2. *Hedging Transactions and Other Transactions Involving Company Derivative Securities*. Hedging or monetization transactions can permit an individual to hedge against a decline in stock price, while at the same time eliminating much of the individual's economic interest in any rise in value of the hedged securities. Because hedging transactions can present the appearance of a bet against the Company, hedging or monetization transactions, whether direct or indirect, involving the Company's securities are completely prohibited, regardless of whether you are in possession of Material,

Non-Public Information. A "short sale," or sale of securities that the seller does not own at the time of sale or, if owned, that will not be delivered within 20 days of the sale, is an example of a prohibited hedging transaction. Bona fide pledges of Company securities as collateral for indebtedness will not be considered hedging for purposes of this Policy.

Transactions involving derivative securities, whether or not entered into for hedging or monetization purposes, may also create the appearance of impropriety in the event of any unusual activity in the underlying equity security. Transactions involving Company-based derivative securities are completely prohibited, whether or not you are in possession of Material, Non-Public Information. "Derivative securities" are options, warrants, stock appreciation rights, convertible notes, or similar rights whose value is derived from the value of an equity security, such as Company securities. Transactions in derivative securities include, but are not limited to, trading in Company-based option contracts, transactions in straddles or collars, and writing or buying puts or calls. Transactions in debt that may be convertible into Company securities would also constitute a transaction in derivative securities prohibited by this Policy. This Policy does not, however, restrict holding, exercising, or settling awards such as options, restricted stock, restricted stock units, or other derivative securities granted under a Company equity incentive plan as described in more detail below under "Exempted Transactions."

3. *Purchases of Company Securities on Margin*. Any of the Company's securities purchased in the open market should be paid for in full at the time of purchase. Purchasing the Company's securities on margin (e.g., borrowing money from a brokerage firm or other third party to fund the stock purchase) is strictly prohibited by this Policy without the prior written approval of the Compliance Officer.

4. *Short-Term Trading*. Short-term trading of Company securities may be distracting and may unduly focus the person on the Company's short-term stock market performance instead of the Company's long-term business objectives. For these reasons, insiders who purchase Company securities in the open market may not sell any Company securities of the same class during the six months following the purchase (or vice versa).

5. *Standing and Limit Orders*. Standing and limit orders (except standing and limit orders under approved Rule 10b5-1 Plans, see Section V below) should be used only for a very brief period of time. The problem with purchases or sales resulting from standing

instructions to a broker is that there is no control over the timing of the transaction. The broker could execute a transaction when the insider is in possession of Material, Non-Public Information.

E. *Exempted Transactions*

This Policy does not apply in the case of the following transactions, except as specifically noted:

1. *Stock Option Exercises*. This Policy does not apply to the exercise of an employee stock option acquired pursuant to the Company's plans, or to the exercise of a tax withholding right pursuant to which a person has elected to have the Company withhold shares subject to an option to satisfy tax withholding requirements. This Policy does apply, however, to any sale of stock as part of a broker-assisted cashless exercise of an option or any other market sale for the purpose of generating the cash needed to pay the exercise price of an option.

2. *Restricted Stock Awards*. This Policy does not apply to the vesting of restricted stock or the exercise of a tax withholding right pursuant to which the insider elects to have the Company withhold shares of stock to satisfy tax withholding requirements upon the vesting of any restricted stock. The Policy does apply, however, to any market sale of restricted stock.

3. *401(k) Plan*. This Policy does not apply to purchases of Company securities in any Company's 401(k) plan resulting from an insider's periodic contribution of money to the plan pursuant to the insider's payroll deduction election. This Policy does apply, however, to certain elections the insider may make under a 401(k) plan, including:

    (a) an election to increase or decrease the percentage of the insider's periodic contributions that will be allocated to the Company stock fund;

    (b) an election to make an intra-plan transfer of an existing account balance into or out of the Company stock fund;

    (c) an election to borrow money against the insider's 401(k) plan account if the loan will result in a liquidation of some or all of the insider's Company stock fund balance; and

    (d) an election to pre-pay a plan loan if the pre-payment will result in allocation of loan proceeds to the Company stock fund.

4. *Employee Stock Purchase Plan*. This Policy does not apply to purchases of Company securities in any employee stock purchase plan adopted by the Company resulting from the insider's periodic contribution of money to the plan pursuant to the election the insider made at the time of the insider's enrollment in the plan. This Policy also does not apply to purchases of Company securities resulting from lump sum contributions to the plan, provided that the insider elected to participate by lump sum payment at the beginning of the applicable enrollment period. This Policy does apply, however, to the insider's election to participate in any such plan for any enrollment period and to the insider's sales of Company securities purchased pursuant to the plan.

5. *Dividend Reinvestment Plan*. This Policy does not apply to purchases of Company securities under any Company's dividend reinvestment plan adopted by the Company resulting from the insider's reinvestment of dividends paid on Company securities. This Policy does apply, however, to voluntary purchases of Company securities resulting from additional contributions the insider chooses to make to a dividend reinvestment plan and to the insider's election to participate in the plan or increase the insider's level of participation in the plan. This Policy also applies to the insider's sale of any Company securities purchased pursuant to the plan.

6. *Other Similar Transactions*. Any other purchase of Company securities from the Company or sales of Company securities to the Company are not subject to this Policy.

F. ***Transactions Not Involving a Purchase or Sale***

Bona fide gifts are not transactions subject to this Policy unless (1) the person making the gift has reason to believe that the recipient intends to sell the Company securities while the officer, employee or Grey Rock Employee, or director is aware of Material, Non-Public Information or (2) the person making the gift is subject to the trading restrictions specified below under the heading "Additional Trading Guidelines and Requirements for Certain Insiders" and the sales by the recipient of the Company securities occur during a blackout period.

Transactions in mutual funds that are invested in Company securities are not transactions subject to this Policy.

G. ***Post-Termination Transactions***

The guidelines set forth in this Section II continue to apply to transactions in the Company's securities even after the insider has terminated employment or other service relationship with the Company as follows: if the insider is aware of

Material, Non-Public Information when his or her employment or service relationship with the Company or Grey Rock terminates, the insider may not trade in the Company's securities until that information has become public or is no longer Material.

H. *No Hardship Waivers*

The guidelines set forth in this Section II may not be waived.

III. Additional Trading Guidelines and Requirements for Certain Insiders

A. *Blackout Period and Trading Window*

The period beginning at the close of market on the 15^{th} calendar day prior to the end of each fiscal quarter or year and ending after two full Trading Days following the date of public disclosure of the financial results for that fiscal quarter ("**Blackout Period**") is a particularly sensitive period of time for transactions in the Company's securities from the perspective of compliance with applicable securities laws. This sensitivity is due to the fact that certain insiders identified by the Company will, during the Blackout Period, often be aware of Material, Non-Public Information about the expected financial results for the quarter. Accordingly, all Company employees and the Grey Rock Employees are prohibited from trading during the Blackout Period. The Company will endeavor to notify employees when the Blackout Period begins. The restrictions in this Section III(A) are in addition to the general prohibitions set forth in this Policy.

To ensure compliance with this Policy and applicable federal and state securities laws, the Company requires Company employees and Grey Rock Employees refrain from executing transactions involving the purchase or sale of the Company's securities other than during the period commencing at the open of market after the expiration of two full Trading Days following the date of public disclosure of the financial results for a particular fiscal quarter or year and continuing until the close of market on the 15^{th} calendar day prior to the end of each fiscal quarter or year ("**Trading Window**"). The safest period for trading in the Company's securities, assuming the absence of Material, Non-Public Information, is generally the first 10 days of the Trading Window.

From time to time, the Company may also prohibit employees from trading the Company's securities because of developments known to the Company and not yet disclosed to the public. In this event, an employee may not engage in any transaction involving the purchase or sale of the Company's securities until the information has been known publicly for at least two full Trading Days and should not disclose to others the fact of the trading suspension.

It should be noted that even during the Trading Window, any person aware of Material, Non-Public Information concerning the Company should not engage in any transactions in the Company's securities until the information has been known publicly for at least two full Trading Days, whether or not the Company has

recommended a suspension of trading to that person. Trading in the Company's securities during the Trading Window should not be considered a "safe harbor," and all insiders should use good judgment at all times.

B. *Pre-Clearance of Trades*

The Company has determined that all officers and directors of the Company and all Grey Rock Employees must not trade in the Company's securities, even during a Trading Window, without first complying with the Company's "pre-clearance" process. Each such Company officer, Company director, or Grey Rock Employee should contact the Company's Compliance Officer prior to commencing any trade in the Company's securities. The Compliance Officer will consult, as necessary, with senior management before clearing any proposed trade. Any proposed trade cleared by the Company's Compliance Officer shall be reported immediately to the Company's Chief Executive Officer.

Please note that clearance of a proposed trade by the Company's Compliance Officer does not constitute legal advice regarding or otherwise acknowledge that any insider does not possess Material, Non-Public Information. Insiders must ultimately make their own judgments regarding, and are personally responsible for determining, whether they are in possession of Material, Non-Public Information.

C. *Hardship Waivers*

The guidelines specified in this Section III may be waived, at the discretion of the Company's Compliance Officer, if compliance would create severe hardship or prevent an insider from complying with a court order, as in the case of a divorce settlement. Any exception approved by the Company's Compliance Officer shall be reported immediately to the Compensation Committee of the Company's Board of Directors (the "**Board**").

IV. Additional Information for Directors and Officers

The Company's directors and Section 16 officers (as defined below) are required to file Section 16 reports with the SEC when they engage in transactions in the Company's securities. Although the Company may generally assist its directors and Section 16 officers in preparing and filing the required reports, directors and Section 16 officers retain responsibility for the reports.

Directors and Section 16 officers shall also comply with the policies and procedures set forth in the Company's Insider Trading Policy.

Further, directors and Section 16 officers may be subject to trading blackouts pursuant to Regulation Blackout Trading Restriction, or Regulation BTR, under the federal securities laws. In general, and with certain limited exemptions, Regulation BTR prohibits any director or Section 16 officer from engaging in certain transactions involving Company securities during periods when participants are prevented from purchasing, selling, or

otherwise acquiring or transferring an interest in certain securities held in individual account plans. The rules encompass a variety of pension plans, including Section 401(k) plans, profit-sharing and savings plans, stock bonus plans, and money purchase pension plans. Any profits realized from a transaction that violates Regulation BTR are recoverable by the Company, regardless of the intentions of the director or Section 16 officer effecting the transaction. In addition, individuals who engage in such transactions are subject to sanction by the SEC as well as potential criminal liability. The Company will notify directors and Section 16 officers if they are subject to a blackout trading restriction under Regulation BTR. Failure to comply with an applicable trading blackout in accordance with Regulation BTR is a violation of law and this Policy.

"**Section 16 officer**" means the Company's president, principal financial officer, principal accounting officer (or if none, the controller), any vice president of the Company in charge of a principal business unit, division, or function (such as sales, administration or finance), and any other officer who performs a policy-making function, as determined from time to time by the Board, or any other person who performs similar policy-making functions of the Company, as determined from time to time by the Board. Officers of the Company's subsidiaries shall also be deemed officers of the Company if they perform policy-making functions for the Company, as determined from time to time by the Board.

V. Planned Trading Programs[2]

Rule 10b5-1 under the Exchange Act provides an affirmative defense to an allegation that a trade has been made on the basis of Material, Non-Public Information. Under the affirmative defense, insiders may purchase and sell securities even when aware of Material, Non-Public Information. To meet the requirements of Rule 10b5-1, each of the following elements must be satisfied.

- The purchase or sale of securities was effected pursuant to a pre-existing plan; and
- The insider adopted the plan while unaware of any Material, Non-Public Information.

The general requirements of Rule 10b5-1 are as follows:

- Without being aware of Material, Non-Public Information, the insider shall have (1) entered into a binding contract to purchase or sell the Company's securities, (2) provided instructions to another person to execute the trade for his or her account or (3) adopted a written plan for trading the Company's securities (each of which is referred to as a "**Rule 10b5-1 Plan**").
- With respect to the purchase or sale of the Company's securities, the Rule 10b5-1 Plan either: (1) expressly specified the amount of the securities (whether a specified

[2] In March of 2009 (and updated December 8, 2016), the SEC published updated Compliance & Disclosure Interpretations ("C&DIs") regarding Rule 10b5-1. (http://www.sec.gov/divisions/corpfin/guidance/exchangeactrules-interps.htm). Such CD&Is should be referenced when implementing, modifying or terminating Rule 10b5-1 Plans.

number of securities or a specified dollar value of securities) to be purchased or sold on a specific date and at a specific price; (2) included a written formula or algorithm, or computer program, for determining the amount of the securities (whether a specified number of securities or a specified dollar value of securities), price and date; or (3) provided an employee or third party who is not aware of Material, Non-Public Information with discretion to purchase or sell the securities without any subsequent influence from the insider over how, when, or whether to trade.

- The purchase or sale that occurred was made pursuant to a written Rule 10b5-1 Plan.[3] The insider cannot deviate from the plan by altering the amount, the price, or the timing of the purchase or sale of the Company's securities. Any deviation from, or alteration to, the specifications will render the defense unavailable. Although deviations from a Rule 10b5-1 Plan are not permissible, it is possible for an insider acting in good faith to modify the plan at a time when the insider is unaware of any Material, Non-Public Information. In such a situation, a purchase or sale that complies with the modified plan will be treated as a transaction pursuant to a new plan. However, as noted below, insiders must comply with the applicable cooling off periods between termination of a Rule 10b5-1 Plan and entry into a new Rule 10b5-1 Plan.

- An insider cannot enter into a corresponding or hedging transaction, or alter an existing corresponding or hedging position, with respect to the securities to be bought or sold under the Rule 10b5-1 Plan.

To help demonstrate that a Rule 10b5-1 Plan meets the good faith requirement and is not part of an insider-trading scheme, the Company has adopted the following guidelines for such plans:

- *Adoption*. Since adopting a plan is tantamount to an investment decision, the Rule 10b5-1 Plan may be adopted only during an open Trading Window when both (1) insider purchases and sales are otherwise permitted under this Policy and (2) the insider does not possess any Material, Non-Public Information. All Rule 10b5-1 Plans must be pre-cleared in writing in advance of adoption by the Compliance Officer or the Board of Directors and prompt disclosure regarding the plan's adoption may be made through a press release or Current Report on Form 8-K. If required by SEC rule or other applicable law, the insider will furnish a written certification regarding its compliance with Rule 10b5-1 at the time of adoption of a plan. Insiders are not permitted to have multiple Rule 10b5-1 Plans in operation. Further, the Rule 10b5-1 Plan should be designed such that it (1) causes a number of smaller sales over a period of time versus a large number of sales over a short period of time and (2) is consistent with the insider's prior trading history to

[3] Insiders filing Form 4 disclosures for trades under a 10b5-1 Plan are required to note that the trade was made pursuant to a Rule 10b5-1 Plan in the disclosure. While not required by law, this disclosure is recommended to avoid suspicion that a trade was executed on the basis of Material, Non-Public Information.

minimize the appearance of sales timed with Material, Non-Public Information. **Please note that the Company retains the right to reject and not permit the adoption of a Rule 10b5-1 Plan for any reason. Further, please note that if trading in the Company's securities is suspended for any reason, such suspension shall take effect notwithstanding the existence of a Rule 10b5-1 Plan.**

- *Initial Trading*. The longer the elapsed time between the adoption of the Rule 10b5-1 Plan and the commencement of trading under such plan, the harder it will be for the SEC to show that the plan was based on Material, Non-Public Information. In addition, a plan that allows trading to commence shortly after the creation of the plan increases the likelihood that the SEC will find, in hindsight, that the plan was not entered into in good faith. Accordingly, for persons other than directors and Section 16 officers, trades may not be made until (1) the first day that the Trading Window opens after the announcement of the results of the quarter in which the Rule 10b5-1 Plan was adopted or (2) a waiting period of 30 days (or such longer period as may be required by SEC rule or other applicable law) has expired after adoption of the plan, whichever is later. However, for directors and Section 16 officers, trades may not be made until (1) the first day that the Trading Window opens after the announcement of the results of the quarter in which the Rule 10b5-1 Plan was adopted or (2) a waiting period of 90 days has expired after the adoption of the plan, whichever is later.

- *Plan Alterations*. The SEC has differentiated between plan deviations and plan modifications. Rule 10b5-1 states that the affirmative defense is not available if the insider altered or *deviated* from the Rule 10b5-1 Plan. On the other hand, *modifications* to Rule 10b5-1 Plans are permitted as long as the insider, acting in good faith, does not possess Material, Non-Public Information at the time of the modification and meets all of the elements required at the inception of the plan. Although not forbidden by Rule 10b5-1, plan modifications, even if prior to receiving Material, Non-Public Information, create the perception that the insider is manipulating the plan to benefit from Material, Non-Public Information, which jeopardizes the good faith element and the availability of the affirmative defense. The SEC has established that a plan modification or amendment to an existing Rule 10b5-1 Plan operates as an adoption of a new Rule 10b5-1 Plan, and thus necessitates a waiting period of the same duration as set forth above. Therefore, any plan modifications should, at minimum, comply with the requirements set forth above for the adoption of a new plan, including the public disclosure requirement and the requirement that trades not be made under the modified plan until (1) the first day that the Trading Window opens after the announcement of the results of the quarter in which the Rule 10b5-1 Plan was modified or (2) the applicable waiting period (as may be required by SEC rule or other applicable law has expired after modification of the plan, whichever is later. Further, the insider should avoid frequent modifications of Rule 10b5-1 Plans because this could raise concern about his or her good faith in establishing the plan. If required by SEC rule or other applicable law, the insider will furnish a written certification regarding its compliance with Rule 10b5-1 at the time of any modification of a plan.

- *Overlapping Plans*. The SEC prohibits a person having more than one Rule 10b5-1 Plan for open market purchases or sales of the Company's securities subject to limited exceptions for "sell to cover" transactions and certain broker-dealer transactions. However, a person may maintain two separate Rule 10b5-1 Plans at the same time, as long as trading under the later commencing plan is not authorized to begin until after all trades under the earlier-commencing plan are completed or expire without execution. For purposes of the waiting period, the date of adoption of the later-commencing plan is deemed to be the date of termination of the earlier commencing plan. Therefore, the effective waiting period of the later-commencing plan would not begin until the earlier plan terminates.

- *Director and Officer Certifications*. Directors and Section 16 officers must include a certification in the relevant 10b5-1 Plan certifying, at the time of adoption of a new or modified plan, that the director or Section 16 officer (1) is not aware of any Material, Non-Public Information and (2) is adopting the 10b5-1 Plan in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b5-1. Such certification shall be included in the Rule 10b5-1 Plan and not as a stand-alone statement.

- *Early Plan Terminations*. Rule 10b5-1 does not expressly forbid the early termination of a Rule 10b5-1 Plan. However, the SEC has made clear that once a Rule 10b5-1 Plan is terminated, the affirmative defense may not apply to any trades that were made pursuant to that plan if such termination calls into question whether the good faith requirement was met or whether the plan was part of a plan or scheme to evade Rule 10b5-1. The real danger of terminating a plan arises if the insider promptly engages in market transactions or adopts a new plan. Such behavior could arouse suspicion that the insider is modifying trading behavior in order to benefit from Material, Non-Public Information. Accordingly, it is not advisable for insiders to terminate Rule 10b5-1 Plans except in unusual circumstances. If a plan is terminated, prompt disclosure regarding such termination may be made through a press release or Current Report on Form 8-K. Furthermore, the Company requires that the insider refrain from engaging in new trades or adopting a new Rule 10b5-1 Plan within 180 days of the termination of a prior plan.

  To allow insiders to terminate Rule 10b5-1 Plans and avoid problems under the federal securities laws, such plans may include the following:

  - a provision expressly stating that the insider reserves the right to terminate the plan under certain specified conditions (in order to demonstrate that any termination is not inconsistent with the plan's original terms);

  - a provision specifying that if the insider terminates the plan and subsequently adopts a new plan, that new plan will not take effect for a period of at least 30 days after its adoption (or 90 days in the case of directors or Section 16 officers); and/or

- a provision automatically terminating the plan at some future date, such as a year after adoption.

If an insider establishes a new Rule 10b5-1 Plan after terminating a prior plan, then all the surrounding facts and circumstances, including the period of time between the cancellation of the old plan and the creation of the new plan, are relevant to a determination of whether the insider established the new Rule 10b5-1 Plan "in good faith and not as part of a plan or scheme to evade" the prohibitions of Rule 10b5-1.

- *Transactions Outside the Plan*. Trading securities outside of a Rule 10b5-1 Plan should be considered carefully for several reasons: (1) the Rule 10b5-1 affirmative defense will not apply to trades made outside of the plan and (2) buying or selling securities outside a Rule 10b5-1 Plan could be interpreted as a hedging transaction. Hedging transactions with respect to securities bought or sold under the Rule 10b5-1 Plan will nullify the affirmative defense. Further, insiders should not sell securities that have been designated as Rule 10b5-1 Plan securities because any such sale may be deemed a modification of the plan. If the insider is subject to the volume limitations of Rule 144, the sale of securities outside the Rule 10b5-1 Plan could effectively reduce the number of shares that could be sold under the plan, which could be deemed an impermissible modification of the plan. Because trading securities outside of a Rule 10b5-1 Plan poses numerous risks, any such transactions must be pre-cleared in accordance with the provision set forth in Section III(B) above.

- *Reporting*. The Company must disclose quarterly (1) whether a director or officer has adopted or terminated any Rule 10b5-1 Plan and (2) the material terms of the Rule 10b5-1 Plan (including the name and title of the director of officer; the date the plan was adopted, modified, or terminated; the plan's duration; and the total amount of securities to be purchased or sold under the plan).

VI. Size of Transaction and Reason for Transaction Do Not Matter

The size of the transaction or the amount of profit received does not have to be significant to result in prosecution. The SEC has the ability to monitor even the smallest trades, and the SEC performs routine market surveillance. Brokers and dealers are required by law to inform the SEC of any possible violations by people who may have Material, Non-Public Information. The SEC aggressively investigates even small insider trading violations.

VII. Potential Criminal and Civil Liability and/or Disciplinary Action

A. *SEC Enforcement Action*

The adverse consequences of insider trading violations can be staggering and currently include, without limitation, the following:

1. For individuals who trade on Material, Non-Public Information (or tip information to others):

- A civil penalty of up to three times the profit gained or loss avoided resulting from the violation;
- A criminal fine of up to $5.0 million (no matter how small the profit); and/or
- A jail term of up to 20 years.

2. For a company (as well as possibly any supervisory person) that fails to take appropriate steps to prevent illegal trading:

    - A civil penalty of up to the greater of $2.01 million or three times the profit gained or loss avoided as a result of the insider's violation;
    - A criminal penalty of up to $25.0 million; and/or
    - The civil penalties may extend personal liability to the Company's directors, officers, and other supervisory personnel if they fail to take appropriate steps to prevent insider trading.

B. *Disciplinary Action by the Company*

Persons who violate this Policy shall be subject to disciplinary action by the Company, which may include termination or other appropriate action.

VIII. Administration of the Policy

The Compliance Officer or another employee designated by the Compliance Officer shall be responsible for administration of this Policy. All determinations and interpretations by the Compliance Officer shall be final and not subject to further review.

* * * * *

This document states a policy of Granite Ridge Resources, Inc. and is not intended to be regarded as the rendering of legal advice.

ANNEX A
INSIDER TRADING POLICY
CERTIFICATION

I have read and understand the Insider Trading Policy (the "**Policy**") of Granite Ridge Resources, Inc. (the "**Company**"). I agree that I will comply with the policies and procedures set forth in the Policy. I understand and agree that, if I am an employee of the Company, one of the Company's subsidiaries or other affiliates, or Grey Rock Administration, LLC ("**Grey Rock**"), my failure to comply in all respects with the Company's policies, including the Policy, is a basis for termination for cause of my employment with the Company, any subsidiary or other affiliate to which my employment now relates or may in the future relate, or Grey Rock, as applicable.

I am aware that this signed Certification will be filed with my personal records in the Company's files or Grey Rock's files, as applicable.

____
Signature

____
Type or Print Name

____
Date

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-268478) and Form S-8 (No. 333-269036) of Granite Ridge Resources, Inc. of our report dated March 6, 2025, with respect to the consolidated financial statements of Granite Ridge Resources, Inc. included in this Annual Report on Form 10-K for the years ended December 31, 2024 and 2023, and for each of the three years in the three-year period ended December 31, 2024.

/s/ Forvis Mazars, LLP

Dallas, Texas
March 6, 2025

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 3, 2025, with respect to estimates of reserves and future net revenue to the Company's interest, as of December 31, 2024, in certain oil and gas properties located in Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Texas, and Wyoming. 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-3 (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 6, 2025

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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

5. 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 6, 2025

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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

5. 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 6, 2025

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 on Form 10-K of Granite Ridge Resources, Inc. (the "Company") for the period ended December 31, 2024, 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 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 6, 2025	By:	/s/ LUKE C. BRANDENBERG	
		Name:	Luke C. Brandenberg
		Title:	*President and Chief Executive Officer*
Dated: March 6, 2025	By:	/s/ TYLER S. FARQUHARSON	
		Name:	Tyler S. Farquharson
		Title:	*Chief Financial Officer*

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS

CHAIRMAN & CEO
RICHARD B. TALLEY, JR.

PRESIDENT & COO
ERIC J. STEVENS

EXECUTIVE COMMITTEE
ROBERT C. BARG
P. SCOTT FROST
JOHN G. HATTNER
JOSEPH J. SPELLMAN

January 3, 2025

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, 2024, 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, 2024, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	17,372.2	104,292.9	935,931.2	634,483.5
Proved Developed Non-Producing	1,897.1	13,810.7	124,330.6	90,982.5
Proved Undeveloped	8,917.6	38,665.6	278,179.0	116,463.0
Total Proved	28,186.9	156,769.2	1,338,441.0	841,928.8

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 2024. For oil volumes, the average West Texas Intermediate spot price of $76.32 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.130 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 $73.82 per barrel of oil and $2.197 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. 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

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chairman and Chief Executive Officer

By: /s/ Nathan C. Shahan
Nathan C. Shahan, P.E. 102389
Vice President

N.C. SHAHAN
102389
LICENSED
PROFESSIONAL ENGINEER

Date Signed: January 3, 2025

NCS:MBG

NETHERLAND, SEWELL & ASSOCIATES, INC.

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.

DEFINITIONS OF OIL AND GAS RESERVES

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

DEFINITIONS OF OIL AND GAS RESERVES

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.