

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, 2022

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
(State or other jurisdiction of
incorporation or organization)

1311
(Primary Standard Industrial
Classification Code Number)

88-2227812
(I.R.S. Employer
Identification Number)

**5217 McKinney Ave, Suite 400,
Dallas, TX 75205**

(Address of principal executive offices)

(214) 396-2850

(Registrant's telephone number, including area code)

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

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

Title of each class	Trading Symbol	Name of each exchange on which registered
Common Stock, par value \$0.0001 per share	GRNT	New York Stock Exchange
Warrants to purchase Common Stock, each whole warrant exercisable for one share of common stock at an exercise price of \$11.50 per share	GRNT WS	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

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

Large accelerated filer ☐

Accelerated filer ☐

Non-accelerated filer ☒

Smaller reporting company ☐

Emerging growth company ☒

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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

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

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

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

As of June 30, 2022, the last business day of the registrant's most recently completed second quarter, there was no public market for the registrant's common stock. The registrant's common stock began trading on the New York Stock Exchange on October 25, 2022.

At March 22, 2023, there were 133,212,500 shares of our common stock, par value \$0.0001, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement related to the registrant's 2023 Annual Meeting of Stockholders are incorporated by reference into Part III of this report for the year ended December 31, 2022.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

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

From time to time, our management or persons acting on our behalf may make forward-looking statements to inform existing and potential security holders about our company. All statements other than statements of historical facts included in this report regarding our financial position, business strategy, plans and objectives of management for future operations, industry conditions, indebtedness covenant compliance, capital expenditures, production, cash flow, borrowing base under our Credit Agreement (as defined below), our intention or ability to pay or increase dividends on our capital stock, and impairment are forward-looking statements. When used in this report, forward-looking statements are generally accompanied by terms or phrases such as "estimate," "project," "predict," "believe," "expect," "continue," "anticipate," "target," "could," "plan," "intend," "seek," "goal," "will," "should," "may" or other words and similar expressions that convey the uncertainty of future events or outcomes. Items contemplating or making assumptions about actual or potential future production, sales, market size, collaborations, cash flows, and trends or operating results also constitute such forward-looking statements.

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

- changes in current or future commodity prices and interest rates;
- supply chain disruptions;
- infrastructure constraints and related factors affecting our properties;
- our ability to acquire additional development opportunities and potential or pending acquisition transactions, as well as the effects of such acquisitions on our company's cash position and levels of indebtedness;
- changes in our reserves estimates or the value thereof;
- operational risks including, but not limited to, the pace of drilling and completions activity on our properties;
- changes in the markets in which Granite Ridge competes;
- geopolitical risk and changes in applicable laws, legislation, or regulations, including those relating to environmental matters;
- cyber-related risks;
- the fact that reserve estimates depend on many assumptions that may turn out to be inaccurate and that any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves;
- the outcome of any known and unknown litigation and regulatory proceedings;

- limited liquidity and trading of Granite Ridge's securities;
- acts of war or terrorism;
- market conditions and global, regulatory, technical, and economic factors beyond Granite Ridge's control, including the potential adverse effects of the COVID-19 pandemic, or another major disease, 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;
- the restatement of our financial statements for the quarter ended September 30, 2022 and our ability to establish and maintain effective internal control over financial reporting, including our ability to remediate the existing material weaknesses in our internal controls; and
- other factors discussed in this Annual Report on Form 10-K under "Risk Factors," as updated by any subsequent Forms 10-Q, which we file with the United States Securities and Exchange Commission ("SEC").

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

Readers are urged not to place undue reliance on these forward-looking statements, which speak only as of the date of this 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.

"*MMBbl.*" One million barrels of crude oil, condensate or NGLs.

"*MMBoe.*" One million Boe.

"*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 price, and the wellhead price received.

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

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

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

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

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

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

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

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

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

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

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

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

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

"NGLs" or "natural gas liquids" Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

"NYMEX" The New York Mercantile Exchange.

"OPEC" The Organization of Petroleum Exporting Countries.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Probable reserves" The additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but which together with proved reserves, are as likely as not to be recovered.

"Proved developed producing reserves (PDPs)" Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional crude oil, NGLs, and natural gas expected to be obtained

through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

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

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

"Proved undeveloped drilling location" A site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

"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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GRANITE RIDGE RESOURCES, INC.
ANNUAL REPORT ON FORM 10-K
FOR FISCAL YEAR ENDED DECEMBER 31, 2022
PART I

Item 1. Business

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

Overview

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

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

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

Business Combination

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

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

Assets of Granite Ridge

We hold interests in wells in core operating areas of the Permian, Eagle Ford, Bakken, Haynesville and Denver-Julesburg ("DJ") plays (collectively, our "Properties"). Non-operated working interests constitute the central part of our investment strategy. However, we have also made certain investments in minerals, and certain other oil and natural gas

assets that are incidental or ancillary to preserve, protect, or enhance our assets, or are acquired as part of a package with the non-operated working interests. The operators of our Properties include public exploration and production companies and experienced private companies.

The following is a summary of information regarding our assets as of December 31, 2022, including reserves information as estimated by our third-party independent reserve engineers, Nederland, Sewell & Associates, Inc.

	As of December 31, 2022									
	Productive Oil Wells			Productive Gas Wells			Average Daily Production (Boe per day)	Proved Reserves (MBoe)	% Oil	% Proved Developed
	Net Acres	Gross	Net	Gross	Net					
Permian	8,662	448	40.82	2	0.02	9,150	25,888	60%	55%	
Eagle Ford	6,498	105	19.08	81	4.26	2,194	8,103	58%	46%	
Bakken	15,030	907	37.73	1	0.20	2,189	5,337	76%	89%	
Haynesville	2,298	—	—	62	12.18	4,640	7,862	0%	64%	
DJ	1,822	681	16.43	70	2.16	1,592	3,344	33%	91%	
Total	34,310	2,141	114.06	216	18.82	19,765	50,534	50%	61%	

Business Strategy

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

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

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

Pay a Quarterly Dividend: We believe that a quarterly cash dividend is the cornerstone of a sustainable and resilient business model. We expect that Granite Ridge will initially pay quarterly cash dividends totaling approximately \$60 million per fiscal year.

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

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

Leverage Data: As an owner in over 2,350 gross wells under 60 operators across seven states and 36 counties/parishes, we have an immense amount of data. We continually invest both human and financial capital to further develop our proprietary information systems to help us make better investment decisions faster.

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

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

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

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

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

Operating Areas

Permian

The Permian Basin extends from southeastern New Mexico into west Texas and is currently one of the most active drilling regions in the United States. The Permian Basin consists of mature legacy onshore oil and liquids-rich natural gas reservoirs. The extensive operating history, favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, horizontal development potential and liquids-rich reserves make the Permian Basin one of the most prolific oil-producing regions in the United States. At December 31, 2022, 51% of our total proved reserves were located in the Permian Basin. During the year ended December 31, 2022, operators completed 134 gross (12.41 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, 2022, 16% of our total proved reserves were located in the Eagle Ford Basin. During the year ended December 31, 2022, operators completed 19 gross (3.62 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, 2022, 10% of our total proved reserves were located in the Bakken Basin. During the year ended December 31, 2022, operators completed 27 gross (0.79 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, 2022, 16% of our total proved reserves were located in the Haynesville Basin. During the year ended December 31, 2022, operators completed 9 gross (2.75 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, 2022, 7% of our total proved reserves were located in the DJ Basin. During the year ended December 31, 2022, operators completed 76 gross (1.21 net) wells in the DJ Basin.

Industry Operating Environment

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

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

Development

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

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

While we regularly have the right to take a portion of our production in kind, we typically elect to have our operating partners market and sell oil and natural gas produced from wells in which we have an interest. Our operating partners coordinate the transportation of our oil and natural gas production from their wells to appropriate pipelines or rail transport facilities pursuant to arrangements that they negotiate and maintain with various parties purchasing the production. We

may, from time to time, enter into financial hedging contracts to help mitigate pricing risk and volatility with respect to differentials.

Competition

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

Marketing and Customers

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

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

The following table sets forth the percentage of revenues attributable to third-party operating partners who have accounted for 10% or more of revenues attributable to our assets during the years ended December 31, 2022, 2021 and 2020.

Major Operators	2022	2021	2020
Operator A	*	*	11 %
Operator B	*	*	13 %
Operator C	12 %	12 %	17 %
Operator D	*	15 %	*
Operator E	10 %	*	*
Operator F	10 %	*	*

* Less than 10%

No other operator accounted for 10% or more of revenue attributable to our assets on a combined basis in the years ended December 31, 2022, 2021, or 2020. The loss of any such operator could adversely affect revenues attributable to the Company's assets in the short term.

Title to Properties

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

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

Seasonality

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

Principal Agreements Affecting Our Business

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

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

At the closing of the Business Combination, we entered into a Management Services Agreement ("MSA") with 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, and Texas require permits for drilling operations, drilling bonds or other forms of financial security, and reports concerning operations, and impose other requirements relating to the exploration and production of oil and natural gas. Such states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the process of drilling, completion, and production, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. Moreover, the current administration has indicated that it expects to impose additional federal regulations limiting access to and production from federal lands. The effect of these regulations is to limit the amount of oil and natural gas that can be produced from the wells in which we participate and to limit the number of wells or the locations at which

our operating partners can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas, and natural gas liquids within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties or other liabilities. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Because such rules and regulations are frequently amended or reinterpreted, and typically become more stringent over time, we are unable to predict the future cost or impact of our and our operating partners' compliance with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and profitability. Additionally, unforeseen environmental incidents may occur on the Properties or past non-compliance with environmental laws or regulations may be discovered, resulting in unforeseen liabilities. Additional proposals, proceedings, and regulations that affect the oil and natural gas industry are regularly considered by Congress; the courts; federal regulatory agencies such as the Federal Energy Regulatory Commission ("FERC"), the U.S. Environmental Protection Agency, and the Bureau of Land Management; and state legislatures and regulatory authorities. We cannot predict when or whether any such proposals may become effective, the substance of those regulations, or the outcome of such proceedings. Therefore, we are unable to predict with certainty the future compliance costs or implications of compliance on profitability.

Regulation of Transportation of Oil

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

Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. On January 20, 2022, the FERC established a new price index for the five-year period which commenced on July 1, 2021.

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

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. In Texas, when oil or natural gas pipelines operate at full capacity, access is generally governed by pro-rationing rules established by the Railroad Commission of Texas ("RRC"), in addition to certain pro-rationing provisions that may be set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to our operating partners to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

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

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

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

Environmental Matters

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

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

The federal Clean Air Act ("CAA") and comparable state laws and regulations impose obligations related to the emission of air pollutants, including emissions from oil and gas sources. Under the CAA and comparable state laws, the Environmental Protection Agency ("EPA") and state environmental regulatory agencies have developed stringent regulations governing both permitting of emissions and emissions of certain air pollutants at specified sources, including certain oil and gas sources. Both existing CAA and state regulations, and any future regulations, may require pre-approval for the construction, expansion, or modification of certain facilities that produce, or which are expected to produce, air emissions. Such regulations may also impose stringent air permit requirements, limit natural gas venting and flaring activity, and require the use of specific equipment or technologies to control emissions. Under the CAA, the EPA has enacted final regulations requiring owners and operators of certain facilities that emit greenhouse gases above certain thresholds to report those emissions. The EPA has also promulgated regulations establishing construction and operating permit requirements for greenhouse gas emissions from stationary sources that already emit conventional pollutants (i.e., sulfur dioxide, particulate matter, nitrogen dioxide, carbon monoxide, ozone, and lead) above certain thresholds. Further,

the CAA requires that owners and operators of stationary sources producing, processing, and storing extremely hazardous substances have a general duty to identify hazards associated with an accidental release, design and maintain a safe facility, and minimize the consequences of any releases that occur. The CAA further requires such facilities that handle more than threshold amounts of extremely hazardous substances to develop risk management plans intended to prevent and minimize impacts if releases do occur.

CAA regulations also include New Source Performance Standards (“NSPS”) for the oil and natural gas source category to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production, storage, transportation, and processing activities. These rules currently require all oil or natural gas wells that have been hydraulically fractured or refractured since November 30, 2016 to be completed using so-called “green completion” technology, which significantly reduces VOC emissions, and has the co-benefit of also limiting methane, a greenhouse gas. These regulations, referred to as NSPS Subpart OOOO and OOOOa, also apply to storage tanks and other equipment in the affected oil and natural gas industry segments, and, commencing with Subpart OOOOa, were designed to also limit methane from new and modified sources in the oil and gas sector. The EPA has since modified and rolled back various aspects of the rules, including removal of the transmission and storage sectors of the oil and gas industry from regulation and of the methane-specific standards for the production and processing segments of the industry. Subsequently, Congress partially overturned that rollback in June 2021. Most recently, on November 2, 2021, the EPA proposed to revise and add to the NSPS program rules, which, if adopted, could have a significant impact on the upstream and midstream oil and gas sectors. The proposed rules would formally reinstate methane emission limitations for new and modified facilities. The proposed rules also would regulate, for the first time under the NSPS program, existing oil and gas facilities. Specifically, EPA’s proposed new rule would require states to implement plans that meet or exceed federally established emission reduction guidelines for oil and natural gas facilities.

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. For example, permitting of discharges of stormwater associated with oil and gas facility construction or operation activities may also be required. 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.

Since the term “Waters of the United States” (“WOTUS”) was defined in a joint rulemaking by the EPA and the USACE in May 2015, the meaning of WOTUS has been heavily litigated and subject to further rulemaking. Most recently, on January 24, 2022, the U.S. Supreme Court agreed to hear a case to determine the propriety of the “significant nexus” interpretation of the rule, which could further impact the scope of the definition of WOTUS. *Sackett v. Env’t Prot. Agency*, No. 21-454, 142 S. Ct. 896 (2022). Oral arguments for *Sackett* were held on October 3, 2022. Regardless, the applicable WOTUS definition affects what CWA permitting or other regulatory obligations may be triggered during development and operation of the Properties, and changes to the WOTUS definition could cause delays in development and/or increase the cost of development and operation of the Properties.

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

The federal Safe Drinking Water Act (“SDWA”), its implementing regulations, and delegated regulatory programs (e.g., state programs) impose requirements on drilling and operation of underground injection wells, including injection wells used for the injection disposal of oil and gas wastes, such as produced water. In addition, the EPA has asserted authority under the SDWA to regulate hydraulic fracturing that uses diesel fuel. The EPA directly administers the Underground Injection Control (“UIC”) program in some states, and in others, administration of all or portions of the

program is delegated to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure that the disposed waters are not leaking into groundwater. In addition, because some states, including Oklahoma and Texas, have become concerned that the injection or disposal of produced water could, under certain circumstances, trigger or contribute to earthquakes, they have issued directives to operators and/or have adopted or are considering additional regulations regarding such disposal methods. Changes in regulations or the inability to obtain permits for new disposal wells in the future may affect the ability of the operators of the Properties to dispose of produced water and ultimately increase the cost of operation of the Properties or delay production schedules. For example, in 2014, the RRC published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant 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 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 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 reopening of Superfund sites that previously received regulatory closure. For example, on August 26, 2022, EPA announced a proposal to designate as hazardous substances perfluorooctanoic acid ("PFOA") and perfluorooctanesulfonic acid ("PFOS"), which have been commonly used in a variety of industrial and consumer products. 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.

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

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

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

Several states, including states where the Properties are located, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado and Texas, have enacted bans on hydraulic fracturing. However, in May 2015, the Texas legislature enacted a bill preempting local bans on hydraulic fracturing. In December 2014, former New York Governor Andrew Cuomo banned hydraulic fracturing

state-wide, and this ban was recently codified in the state's Fiscal Year 2021 budget. In Colorado, the Colorado Supreme Court has ruled the municipal bans were preempted by state law. However, in April 2019 the Colorado legislature subsequently enacted "SB 181" that gave significant local control over oil and gas well head operations. Municipalities in Colorado have enacted local rules restricting oil and gas operations based on SB 181; nevertheless, in November 2020, a Colorado district court upheld the prior Colorado Supreme Court ruling in finding that a hydraulic fracking ban in the City of Longmont was preempted by state law. We cannot predict whether other similar legislation in other states will ever be enacted and if so, what the provisions of such legislation would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, it could lead to delays, increased operating costs and process prohibitions that would materially adversely affect our operating partners and our revenues and results of operations.

The National Environmental Policy Act ("NEPA") establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA. If, for example, our third-party operating partners conduct activities on federal land, receive federal funding, or require federal permits, such activities may be covered under NEPA. Certain activities are subject to robust NEPA review which could lead to delays and increased costs that could materially adversely affect our revenues and results of operations. Other activities are covered under categorical exclusions which results in a shorter NEPA review process. In April 2022, the Biden Administration finalized a rule to undo some of the changes to NEPA enacted under the Trump Administration that were intended to streamline NEPA review (the "2020 NEPA Rule"). The April 2022 rule promulgation is considered phase one of a two-phase review of the 2020 NEPA Rule that was announced by the Biden Administration to emphasize the need to review federal actions for climate change and environmental justice impacts, among other factors. These new and (if enacted) additional anticipated changes to the NEPA review process would affect the assessment of projects ranging from oil and natural gas leasing to development on public and Indian lands.

Climate Change

The energy industry is affected from time to time in varying degrees by political developments and a wide range of federal, tribal, state and local statutes, rules, orders and regulations that may, in turn, affect the operations and costs of the companies engaged in the energy industry. In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, require preconstruction and operating permits for GHG emissions from certain large stationary sources that already emit conventional pollutants above a certain threshold. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which may include operations on the Properties. Further, the Inflation Reduction Act ("IRA"), which passed in August 2022, includes a charge for methane emissions from specific types of facilities that emit 25,000 metric tons of carbon dioxide equivalent or more per year, and although the IRA generally provides for a conditional exemption under certain circumstances, the charge applies to emissions that exceed an established emissions threshold for each type of covered facility. The charge starts at \$900 per metric ton of methane in 2025 (using 2024 data), and increases to \$1,500 after two years. While Congress has from time to time considered legislation to reduce emissions of GHGs, in recent years there has not been significant activity at the federal level in the form of adopted legislation aimed at reducing GHG emissions.

In the absence of comprehensive federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact us, any future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, operators' equipment and operations could require it to incur costs to reduce emissions of GHGs associated with its operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and gas produced from the Properties. Restrictions on emissions of methane or carbon dioxide, such as restrictions on venting and flaring of natural gas or increased fuel or energy efficiency requirements, that may be imposed in various states, as well as state and local climate change initiatives, could adversely affect the oil and natural gas industry, and, at this time,

it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact oil and natural gas assets.

Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as greenhouse gas cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there exists the United Nations-sponsored Paris Agreement, which is a non-binding agreement for nations to limit their greenhouse gas emissions through individually determined reduction goals every five years after 2020. While the United States under the Trump Administration withdrew from the Paris Agreement effective November 4, 2020, President Biden recommitted the United States to the Paris Agreement on January 20, 2021. 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.

Environmental, social, and governance ("ESG") goals and programs, which typically include extralegal targets related to environmental stewardship, social responsibility, and corporate governance, have become an increasing focus of investors and stockholders across the industry. While reporting on ESG metrics is currently voluntary, access to capital and investors is likely to favor companies with robust ESG programs in place. Furthermore, in March 2022 the SEC proposed rule amendments that, if adopted, would require public companies to disclose certain climate-related information in their public filings. If adopted, the new requirements would begin to phase-in starting in 2023 and would begin to apply to filings made in 2024. 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.

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

Human Capital Resources

As of December 31, 2022, we had two full time employees. We have an MSA with the Manager, pursuant to which the Manager provides general and administrative, engineering, land, contract administration, tax, accounting, legal and compliance services to us.

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

Office Locations

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.

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.

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.
- Inflation could adversely impact Granite Ridge's ability to control its costs, including its operating partners.
- The COVID-19 pandemic has had, and may continue to have, a material adverse effect on Granite Ridge's financial condition and results of operations.
- Various laws and regulations govern aspects of the oil and gas business including natural resource conservation and environmental, health, and safety matters, and these laws and regulations could change and become stricter over time.
- Fuel and energy conservation measures, technological advances and negative shift in market perception towards the oil and natural gas industry could reduce demand for oil and natural gas.
- Increased attention to environmental, social and governance matters may impact Granite Ridge's business.
- Granite Ridge relies on the Manager for various certain key services under the MSA, which could result in conflicts of interest and other unforeseen risks.
- Certain of our unaudited financial statements for the three and nine months ended September 30, 2022 were required to be restated and our management identified material weaknesses in our internal control over financial reporting. If we do not effectively remediate these material weaknesses or if we otherwise fail to maintain effective disclosure controls and procedure or internal control over financial reporting, our ability to report our financial results on a timely and accurate basis may be adversely impacted, which in turn may adversely affect the market price of our common stock.
- The relative lack of public company experience by Granite Ridge's management team may put Granite Ridge at a competitive disadvantage.
- The borrowing base under our Credit Agreement may be reduced in light of commodity price declines, which could limit us in the future.

- 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.

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.
- The exercise of the Granite Ridge warrants could adversely affect the market price of Granite Ridge common stock and result in dilution to holders of Granite Ridge common stock.
- 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.”
- Granite Ridge could be adversely affected by changes in applicable tax laws, regulations, or administrative interpretations thereof in the United States or other jurisdictions.

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

Risks Related to Our Business and Operations

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

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

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

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

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

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

Our business depends on third-party transportation and processing facilities and other assets that are owned by third parties.

The marketability of our oil and natural gas depends in part on the availability, proximity and capacity of pipeline systems, processing facilities, oil trucking fleets and rail transportation assets owned by third parties. The lack of available capacity on these systems and facilities, whether as a result of proration, growth in demand outpacing growth in capacity, physical damage, adverse weather events or natural disasters, equipment malfunctions or failures, scheduled or unscheduled maintenance, legal or other reasons, could result in a substantial increase in costs, declines in realized commodity prices, the shut-in of producing wells, or the delay or discontinuance of development plans for the Properties. In many cases, operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. In addition, our wells may be drilled in locations that are serviced to a limited extent, if at all, by gathering and transportation pipelines, which may or may not have sufficient capacity to transport production from all of the wells in the area. As a result, we may rely on third-party oil trucking to transport a significant portion of our production to third-party transportation pipelines, rail loading facilities, and other market access points.

In addition, the third parties on whom operators rely for transportation services are subject to complex federal, state, tribal, and local laws that could adversely affect the cost, manner, or feasibility of conducting business on the Properties. Further, concerns about the safety and security of oil and gas transportation by pipeline may result in public opposition to pipeline development and increased regulation of pipelines by the Pipeline and Hazardous Materials Safety Administration, and therefore less capacity to transport our products by pipeline. Any significant curtailment in gathering system or transportation, processing, or refining-facility capacity could reduce our operating partners' ability to market oil production and have an adverse effect on us. Operators' access to transportation options and the prices they receive can also be affected by federal and state regulation — including regulation of oil production, transportation, and pipeline safety — as well as by general economic conditions and changes in supply and demand.

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

We rely on continued contributions of the members of the Manager's management team by virtue of the MSA. Our success depends heavily upon the continued contributions of those members of the Manager's management team whose knowledge, relationships with industry participants, leadership, and technical expertise would be difficult to replace. In particular, our ability to successfully acquire additional properties, to increase our reserves, to participate in drilling opportunities, and to identify and enter into commercial arrangements depends on developing and maintaining close working relationships with industry participants. In addition, our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment is dependent on the Manager's management team's knowledge and expertise in the industry. To continue to develop our business, we rely on the Manager's management team's knowledge and expertise in the industry and will use the Manager's management team's relationships with industry participants to enter into strategic relationships. The members of the Manager's management team may terminate their employment with the Manager at any time. If the Manager were to lose key members of its management team, neither the Manager nor we may be able to replace the knowledge or relationships that they possess, and our ability to execute our business plan could be materially harmed. As a result, our operations and financial condition could suffer.

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

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

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

- changes in global supply and demand for oil and natural gas;
- the actions of OPEC and other major oil producing countries;
- worldwide and regional economic, political and social conditions impacting the global supply and demand for oil and natural gas, which may be driven by various risks including war, terrorism, political unrest, or health epidemics (such as the global COVID-19 coronavirus outbreak);
- the price and quantity of imports of foreign oil and natural gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity, particularly those in the Middle East, Russia, South America and Africa;
- the outbreak or escalation of military hostilities, including between Russia and Ukraine, 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 outbreak of disease;
- technological advances affecting energy consumption;
- domestic and foreign governmental taxes, tariffs and/or regulations;
- proximity and capacity of processing, gathering, storage, oil and natural gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and natural gas in captive market areas; and
- the price and availability of alternative fuels.

These factors and the volatility of the energy markets make it extremely difficult to predict oil and natural gas prices. A substantial or extended decline in oil or natural gas prices, such as the significant and rapid decline that occurred in 2020, has resulted in and could result in future impairments of our proved oil and natural gas properties and may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. To the extent commodity prices received from production are insufficient to fund planned capital

expenditures, we may be required to reduce spending or borrow or issue additional equity to cover any such shortfall. Lower oil and natural gas prices may limit our ability to comply with the covenants under any credit facilities (or other debt instruments) and/or limit our ability to access borrowing availability thereunder, which is dependent on many factors including the value of our proved reserves.

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

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

- declines in oil or natural gas prices, as occurred in 2020 in connection with the COVID-19 pandemic;
- infrastructure limitations, such as gas gathering and processing constraints;
- the high cost, shortages or delays of equipment, materials and services;
- unexpected operational events, adverse weather conditions and natural disasters, facility or equipment malfunctions, and equipment failures or accidents;
- title problems;
- pipe or cement failures and casing collapses;
- lost or damaged oilfield development and service tools;
- compliance with environmental, health, safety and other governmental requirements;
- increases in severance taxes;
- regulations, restrictions, moratoria and bans on hydraulic fracturing;
- unusual or unexpected geological formations, and pressure or irregularities in formations;
- loss of drilling fluid circulation;
- environmental hazards, such as oil, natural gas or well fluids spills or releases, pipeline or tank ruptures and discharges of toxic gas;
- fires, blowouts, craterings and explosions;
- uncontrollable flows of oil, natural gas or well fluids; and
- pipeline capacity curtailments.

In addition to causing curtailments, delays and cancellations of drilling and producing operations, many of these events can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination, loss of wells, regulatory penalties and third party

claims. We ordinarily maintain insurance against various losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

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

A portion of our acreage is not currently held by production or held by operations. Unless production in paying quantities is established or operations are commenced on units containing these leases during their terms, the leases will expire. If our leases expire and we are unable to renew the leases, we will lose our right to participate in the development of the related Properties. Drilling plans for these areas are generally in the discretion of third-party operators and are subject to change based on various factors that are beyond our control, such as: the availability and cost of capital, equipment, services and personnel; seasonal conditions; regulatory and third-party approvals; oil and natural gas prices; results of title work; gathering system and other transportation constraints; drilling costs and results; and production costs. As of December 31, 2022, we had leases that were not developed that represented 4,845 net acres potentially expiring in 2023, 2,423 net acres potentially expiring in 2024 and 628 net acres potentially expiring in 2025 and beyond.

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

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

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

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

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

In 2020, we were required to write down the carrying value of certain properties that constitute our oil and natural gas properties, and further writedowns could be required by us in the future. Under the successful efforts method of accounting, capitalized costs related to proved oil and natural gas properties, including wells and related support equipment and

facilities, are evaluated for impairment on an annual basis, or more frequently if indicators of impairment exist. If undiscounted cash flows are insufficient to recover the net capitalized costs, an impairment charge for the difference between the net capitalized cost of proved properties and their estimated fair values is recognized. A substantial or extended decline in oil or natural gas prices, could result in future impairments of our proved oil and natural gas properties.

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

Determining the amount of oil and natural gas recoverable from various formations involves significant complexity and uncertainty. No one can measure underground accumulations of oil or natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and/or natural gas and assumptions concerning future oil and natural gas prices, production levels, and operating, exploration and development costs. Some of our reserve estimates are made without the benefit of a lengthy production history and are less reliable than estimates based on a lengthy production history. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate.

We routinely make estimates of oil and natural gas reserves in connection with managing our business and preparing reports to our lenders and investors, including estimates prepared by our independent reserve engineering firm. Although the reserve information contained herein is reviewed by our independent reserve engineers, estimates of crude oil and natural gas reserves are inherently imprecise. The process also requires economic assumptions about matters such as oil and natural gas prices, development schedules, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our estimated reserves relies in part on the ability of the Manager's reserve engineers to make accurate assumptions. Any significant variance from these assumptions by actual figures could greatly affect our estimated reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. Numerous changes over time to the assumptions on which our estimated reserves are based result in the actual quantities of oil and natural gas our operating partners ultimately recover being different from our estimated reserves. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K, subsequent reports we file with the SEC or other Company materials.

The present value of future net cash flows from our proved reserves is not necessarily the same as the current market value of our estimated proved reserves.

We base the estimated discounted future net cash flows from our proved reserves using specified pricing and cost assumptions. However, actual future net cash flows from our oil and natural gas properties will be affected by factors such as the volume, pricing and duration of our oil and natural gas hedging contracts; actual prices we receive for oil and natural gas; our actual operating costs in producing oil and natural gas; the amount and timing of our capital expenditures; the amount and timing of actual production; and changes in governmental regulations or taxation. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

Our future success depends on our ability to replace reserves that our operators produce.

Because the rate of production from oil and natural gas properties generally declines as reserves are depleted, our future success depends upon our ability to economically find or acquire and produce additional oil and natural gas reserves. Except to the extent that we acquire additional properties containing proved reserves, conduct successful exploration and development activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline as our reserves are produced. Future oil and natural gas production, therefore, is highly dependent upon our level of success in acquiring or finding additional reserves that are economically recoverable. We cannot assure you that we will be able to find or acquire and develop additional reserves at an acceptable cost.

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

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

Drilling and producing activities and other operations in some of our operating areas could be adversely affected by extreme weather conditions, such as floods, lightning, drought, ice and other storms, prolonged freeze events, and tornadoes, which may cause a loss of production from temporary cessation of activity, or lost or damaged facilities and equipment on the part of our operating partners. Such extreme weather conditions could also impact other areas of operations for our operating partners, including access to drilling and production facilities for routine operations, maintenance and repairs and the availability of, and access to, necessary third-party services, such as electrical power, water, gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt operations on the affected Properties and materially increase operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

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

Approximately 39% of our estimated net proved reserves volumes were classified as proved undeveloped as of December 31, 2022. 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 its 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.

The ongoing military conflict between Ukraine and Russia 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 the conflict in Ukraine or any other geopolitical tensions.

U.S. and global markets are experiencing volatility and disruption following the escalation of geopolitical tensions and the start of the military conflict between Russia and Ukraine. On February 24, 2022, a large-scale military invasion of Ukraine by Russian troops was reported. Although the length and impact of the ongoing military conflict is highly unpredictable, the conflict in Ukraine has led and could lead to significant market and other disruptions, including significant volatility in commodity prices and supply of energy resources, instability in credit and capital markets, supply chain interruptions, political and social instability, changes in consumer or purchaser preferences as well as increase in cyberattacks and espionage. Various of Russia's actions have led to sanctions and other penalties being levied by the U.S., the European Union, and other countries, as well as other public and private actors and companies, against Russia and certain other geographic areas, including agreement to remove certain Russian financial institutions from the Society for Worldwide Interbank Financial Telecommunication ("SWIFT") payment system, expansive bans on imports and exports of products to and from Russia (including imports of Russian oil, liquefied natural gas and coal) and a ban on exportation of U.S. denominated banknotes to Russia or persons located therein. These disruptions in the oil and gas markets have caused, and could continue to cause, significant volatility in energy prices, which could have a material effect on our business. Additional potential sanctions and penalties have also been proposed and/or threatened.

In addition, the United States and other countries have imposed sanctions on Russia which increases the risk that Russia, as a retaliatory action, may launch cyberattacks against the United States, its government, infrastructure and

businesses. On March 21, 2022, the Biden Administration issued warnings about the potential for Russia to engage in malicious cyber activity against the United States in response to the economic sanctions that have been imposed.

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

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

Although inflation in the United States has been relatively low in recent years, it has risen significantly beginning in the second half of 2021. This is believed to be the result of the economic impact from the COVID-19 pandemic, including the effects of global supply chain disruptions and government stimulus packages, among other factors. Global, industry-wide supply chain disruptions caused by the COVID-19 pandemic have resulted in shortages in labor, materials and services. Such shortages have resulted in inflationary cost increases for labor, materials and services and could continue to cause costs to increase as well as scarcity of certain products and raw materials. To the extent elevated inflation remains, our operating partners may experience further cost increases for their operations, including oilfield services and equipment as increasing oil and natural gas prices increase drilling activity in our operating partners' areas of operations, as well as increased labor costs. An increase in oil and natural gas prices may cause the costs of materials and services to rise. We cannot predict any future trends in the rate of inflation and any continued significant increase in inflation, to the extent we are unable to recover higher costs through higher commodity prices and revenues, would negatively impact our business, financial condition and results of operation.

The COVID-19 pandemic has had, and may continue to have, a material adverse effect on our financial condition and results of operations.

We face risks related to public health crises, including the COVID-19 pandemic. The effects of the COVID-19 pandemic, including travel bans, prohibitions on group events and gatherings, shutdowns of certain businesses, curfews, shelter-in-place orders and recommendations to practice social distancing in addition to other actions taken by both businesses and governments, resulted in a significant and swift reduction in international and U.S. economic activity.

The collapse in the demand for oil caused by this unprecedented global health and economic crisis contributed to the significant decrease in crude oil prices in 2020 and had and could in the future continue to have a material adverse impact on our financial condition and results of operations.

Since the beginning of 2021, the distribution of COVID-19 vaccines progressed, and many government-imposed restrictions were relaxed or rescinded. However, we continue to monitor the effects of the pandemic on our operations. As a result of the ongoing COVID-19 pandemic, our operations, and those of our operating partners, have and may continue to experience delays or disruptions and temporary suspensions of operations. In addition, our results of operations and financial condition have been and may continue to be adversely affected by the ongoing COVID-19 pandemic.

The extent to which our operating and financial results are affected by COVID-19 will depend on various factors and consequences beyond our control, such as the emergence of more contagious and harmful variants of the COVID-19 virus, the duration and scope of the pandemic, additional actions by businesses and governments in response to the pandemic, and the speed and effectiveness of responses to combat the virus. COVID-19, and the volatile regional and global economic conditions stemming from the pandemic, could also aggravate the other risk factors that we identify herein. While the effects of the COVID-19 pandemic have lessened recently in the United States, we cannot predict the duration or future effects of the pandemic, or more contagious and harmful variants of the COVID-19 virus, and such effects may materially adversely affect our results of operations and financial condition in a manner that is not currently known to us or that we do not currently consider to present significant risks to our operations.

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 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, or that third-party service providers could cause a breach of our data. We believe that we and the Manager have positive relations with their information technology vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our or the Manager's arrangements with third parties for their computing and communications infrastructure or any other interruptions to, or breaches of, their information systems could lead to data corruption, communication interruption, loss of sensitive or confidential information or otherwise significantly disrupt our business operations. Although we and the Manager utilize various procedures and controls to monitor these threats and mitigate their exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. Furthermore, various third-party resources that we or the Manager rely on, directly or indirectly, in the operation of our business (such as pipelines and other infrastructure) could suffer interruptions or breaches from cyber-attacks or similar events that are entirely outside the control of us or the Manager, and any such events could significantly disrupt our business operations and/or have a material adverse effect on our results of operations. We have not, to our knowledge, experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer material losses in the future.

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.

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 where 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. Failure to comply with applicable environmental laws and regulations by us or third-party operators or contractors could trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements or other corrective measures, and the issuance of orders enjoining existing or future operations. In addition, we or our operating partners may be strictly liable under state or federal laws for environmental damages caused by the previous owners or operators of properties they purchase, without regard to fault.

Environmental laws and regulations change frequently and tend to become more stringent over time, and the implementation of new, or the modification of existing, laws or regulations could adversely affect our business. For example, in recent years, the EPA published final rules that establish new air emission control requirements, among other requirements, for oil and natural gas production, processing, transportation, and storage activities to address emissions of methane and VOCs. Among these requirements is the reduction of methane and VOC emissions from oil and gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells subject to the rule. These NSPSs, as so referred, also impose requirements for leak detection and repair at well sites and natural gas transmission compressor stations and professional engineer certifications of emission control systems installed to comply with the rule. These rules have been heavily litigated and some aspects of them continue to be subject to various challenge, rescission, and proposal actions. Accordingly, the final implementation and scope of these requirements remains uncertain, but the imposition of these requirements on certain sources of air emissions in the oil and gas industry that were constructed, reconstructed, or modified on or after August 23, 2011, will likely result in increased costs for oil and natural gas exploration and production activities. Furthermore, EPA in November 2021 proposed a suite of NSPS rules, known as Subparts OOOOb and OOOOc that, if adopted, will further impact the upstream and midstream oil and gas sectors. As proposed, Subparts OOOOb and OOOOc would impose requirements on new, modified, existing and/or reconstructed sources in the oil and natural gas sector. The proposed regulations include additional inspections, emission control requirements, additional financial assurance for plugged and abandoned wells, and emissions guidelines to assist states in

the development of plans to regulate methane emissions from certain existing sources. The proposed rules for new and modified facilities are currently estimated to be finalized soon, while any standards finalized for existing facilities will require further state rulemaking actions over the next several years before they become effective. The proposed rules and any state standards, if implemented, could further increase the cost of development and operation of the Properties.

Additionally, some states in which the Properties are located, such as Colorado and New Mexico, have adopted stringent rules and regulations to reduce methane emissions and emissions of other hydrocarbons, VOCs, and nitrogen oxides associated with oil and gas facilities. For example, the Colorado Department of Public Health and Environment's Air Quality Control Commission ("AQCC") recently adopted more stringent standards for leak detection and repair inspection frequency, pipeline and compressor station inspection and maintenance frequencies, the development of pre-production air monitoring plans at certain oil and gas facilities, enclosed combustion device testing, a methane intensity reduction requirement based on statewide volume of production and additional measures for reducing and eliminating emissions from pneumatic devices. AQCC is expected to undertake several additional rulemaking efforts to further reduce emissions over the next several years. 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. 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.

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

The energy industry is affected from time to time in varying degrees by political developments and a wide range of federal, tribal, state and local statutes, rules, orders and regulations that may, in turn, affect the operations and costs of the companies engaged in the energy industry. In response to findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, require preconstruction and operating permits for GHG emissions from certain large stationary sources that already emit conventional pollutants above a certain threshold. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which may include operations on the Properties. Further, the IRA, which the U.S. Congress passed in August 2022, includes a charge for methane emissions from specific types of facilities that emit 25,000 metric tons of carbon dioxide equivalent or more per year, and although the IRA generally provides for a conditional exemption under certain circumstances, the charge applies to emissions that exceed an established emissions threshold for each type of covered facility. The charge starts at \$900 per metric ton of methane in 2025 (using 2024 data), and increases to \$1,500 after two years. Additional GHG regulation could also result from the agreement crafted during the United Nations climate change conference in Paris, France in December 2015 (the "Paris Agreement"). Under the Paris Agreement, the United States committed to reducing its GHG emissions by 26-28% by the year 2025 as compared with 2005 levels. Moreover, in November 2021, at the U.N. Framework Convention on Climate Change 26th Conference of the Parties, the U.S. and the European Union advanced a Global Methane Pledge to reduce global methane emissions at least 30% from 2020 levels by 2030, which over 100 countries have signed. While Congress has from time to time considered legislation to reduce emissions of GHGs, comprehensive legislation aimed at reducing GHG emissions has not yet been adopted at the federal level.

In the absence of comprehensive federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact us, any future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, operators' equipment and operations could require them to incur costs to reduce emissions of GHGs

associated with their operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and gas produced from the Properties. Restrictions on emissions of methane or carbon dioxide, such as restrictions on venting and flaring of natural gas, that may be imposed in various states, as well as state and local climate change initiatives, such as increased energy efficiency standards or mandates for renewable energy sources, could adversely affect the oil and gas industry, and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact oil and gas assets. Finally, it should be noted that climate changes may have significant physical effects, such as increased frequency and severity of storms, freezes, floods, drought, hurricanes and other climatic events; if any of these effects were to occur, they could have an adverse effect on us.

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

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

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

Additionally, certain segments of the investor community have recently expressed negative sentiment towards investing in the oil and natural gas industry. Recent equity returns in the sector versus other industry sectors have led to lower oil and natural gas representation in certain key equity market indices. Some investors, including certain pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on social and environmental considerations. Furthermore, certain other stakeholders have pressured commercial and investment banks to stop funding oil and gas exploration and production and related infrastructure projects. With the continued volatility in oil and natural gas prices, and the possibility that interest rates will continue to rise in the future, increasing the cost of borrowing, certain investors have emphasized capital efficiency and free cash flow from earnings as key drivers for energy companies, especially shale producers. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

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

Increased attention to ESG matters may impact our business.

Increasing attention to climate change, fuel conservation measures, alternative fuel requirements, incentives to conserve energy or use alternative energy sources, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on our access to capital markets. Increasing attention to climate change and any related negative public perception regarding us and/or our industry, for example, may result in demand shifts for our products, increased litigation risk for us, and increased regulatory, legislative

and judicial scrutiny, which may, in turn, lead to new state, local, tribal and federal safety and environmental laws, regulations, guidelines and enforcement interpretations.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may, of their own accord, elect not to provide or place additional restrictions on funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

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

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

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

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

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

Certain of our unaudited financial statements for the three and nine months ended September 30, 2022 were required to be restated, and our management identified material weaknesses in our internal control over financial reporting. If we do not effectively remediate these material weaknesses or if we otherwise fail to maintain effective disclosure controls and procedures or internal control over financial reporting, our ability to report our financial results on a timely and accurate basis may be adversely impacted, which in turn may adversely affect the market price of our common stock.

Our management and audit committee concluded that our previously issued unaudited condensed combined financial statements as of and for the three and nine month periods ended September 30, 2022, included in the Company's Quarterly Report on Form 10-Q filed on November 14, 2022 (the "Original Form 10-Q"), were materially misstated. Management

and the audit committee concluded that these financial statements should no longer be relied upon. We filed Amendment No. 1 to the Original Form 10-Q on March 10, 2023 in order to correct the errors by restating our previously issued unaudited condensed combined financial statements as of and for the three and nine month periods ended September 30, 2022.

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

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

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

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

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

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

As a company with a class of securities that are registered under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), we are subject to reporting and other legal, accounting, corporate governance, and regulatory requirements imposed by the Exchange Act or the Sarbanes-Oxley Act. With the exception of our Chief Financial Officer and Chief Accounting Officer, Granite Ridge’s management team lacks public company experience, which could impair our ability to comply with these legal, accounting, and regulatory requirements. Such responsibilities include complying with securities laws and making required disclosures on a timely basis. Our senior management may not be able to implement and effect programs and policies in an effective and timely manner that adequately respond to such increased legal and regulatory compliance and reporting requirements. Our failure to do so could lead to the imposition of fines and penalties and negatively impact our business and operations.

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

At the closing of the Business Combination, we entered into a Credit Agreement, secured by a first priority mortgage and security interest in substantially all of our assets and our restricted subsidiaries. Availability under the Credit Agreement is limited to the aggregate commitments of the lenders, which is the least of the aggregate maximum credit amounts of the lenders, the borrowing base and the elected commitment amount chosen by us. 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.

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

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

or financial markets, or concerns or negative expectations about the prospects for companies in the financial services industry.

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

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 connection with the Business Combination, ENPC Holdings II, LLC, a Delaware limited liability company ("Holdco") and the former independent directors of Executive Network Partnering Corporation, a Delaware corporation ("ENPC") received 1,238,393 shares of our common stock (of which an aggregate of 220,348 shares were subsequently forfeited pursuant to the terms of that certain Sponsor Agreement, dated May 16, 2022, by and among ENPC Holdings, LLC, Holdco, ENPC, Granite Ridge, GREP and certain other parties named therein (the "Sponsor Agreement")) and the holders of GREP (the "Existing GREP Members") and their direct and indirect members were issued 130.0 million shares of our common stock. Pursuant to the terms and subject to the conditions of the Registration Rights and Lock-Up Agreement, dated as of October 24, 2022, by and among Granite Ridge, Holdco, Richard Boyce, Michael M. Calbert, Gisel Ruiz and the Existing GREP Members, the Existing GREP Members are not be able to sell any of the shares of our common stock that they received as a result of the Business Combination (subject to limited exceptions) until 180 days after the consummation of the Business Combination. In connection with and in order to facilitate the closing of the Business Combination, we granted a waiver of the lock-up restriction with respect to certain shares. The lock-up restrictions with respect to certain other shares were waived subsequent to the closing of the Business Combination.

Holdco may sell, and upon expiration of the applicable lock-up periods and subject to applicable securities laws, the Existing GREP Members may sell large amounts of shares of our common stock in the open market or in privately negotiated transactions, which could have an adverse impact on our stock price.

As restrictions on resale end, the market price of shares of our common stock could drop significantly if our securityholders sell them or are perceived by the market as intending to sell them. These factors could also make it more difficult for us to raise additional funds through future offerings of shares of our common stock or other securities.

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 number of shares of our common stock expected to be reserved for future issuance under our equity incentive plans is 6,500,000, which represented approximately 4.9% of the shares of our common stock that are outstanding following the consummation of the Business Combination. We have filed a registration statement on Form S-8 under 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.

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;
- success of competitors;
- 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;
- 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.

In the past, following periods of market volatility, stockholders have instituted securities class action litigation. If we are involved in securities litigation, it could have a substantial cost and divert resources and the attention of executive management from our business regardless of the outcome of such litigation.

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 \$1.07 billion or (c) in which we are deemed to be a large accelerated filer, which means (1) the market value of our common stock that is held by non-affiliates exceeds \$700 million as of the last business day of our most recently completed second fiscal quarter (2) has been subject to compliance with periodic reporting requirements for a period of at least 12 months, and (3) the date on which we have issued more than \$1.0 billion in non-convertible debt securities during the prior three year period. We cannot predict whether investors will find our securities less attractive because it will rely on these exemptions. If some investors find our securities less attractive as a result of our reliance on these exemptions, the trading prices of our securities may be lower than they otherwise would be, there may be a less active trading market for our securities and the trading prices of our securities may be more volatile.

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

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

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

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

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

The exercise of our warrants would increase the number of shares eligible for future resale in the public market and result in dilution to holders of our common stock.

Our outstanding warrants to purchase an aggregate 10,349,975 shares of our common stock are exercisable in accordance with the terms of our warrant agreement governing the warrants. To the extent such warrants are exercised, additional shares of our common stock will be issued, which will result in dilution to the holders of our common stock and may increase the number of shares eligible for resale in the public market. Sales of substantial numbers of such shares in the public market could adversely affect the market price of our common stock.

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

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

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

These anti-takeover provisions could make it more difficult for a third-party to acquire us, even if the third party's offer may be considered beneficial by many of our stockholders. As a result, our stockholders may be limited in their

ability to obtain a premium for their shares. These provisions could also discourage proxy contests and make it more difficult for you and other stockholders to elect directors of your choosing and to cause us to take other corporate actions you desire.

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

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

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

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

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

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

shall be deemed to have notice of and consented to this exclusive forum provision, but will not be deemed to have waived our compliance with the federal securities laws and the rules and regulations thereunder.

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

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

- the requirement that a majority of our Board of Directors consist of independent directors;
- the requirement that our director nominations be made, or recommended to the full Board of Directors, by our independent directors or by a nominations committee that is comprised entirely of independent directors and that we adopt a written charter or board resolution addressing the nominations process; and
- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee’s purpose and responsibilities.

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

We could be adversely affected by changes in applicable tax laws, regulations, or administrative interpretations thereof in the United States or other jurisdictions.

We could also be adversely affected by changes in applicable tax laws, regulations, or administrative interpretations thereof in the United States or other jurisdictions and changes in tax law could reduce our after-tax income and adversely affect our business and financial condition. For example, the U.S. federal tax legislation commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”), enacted in December 2017, resulted in fundamental changes to the Code, as amended, including, among many other things, a reduction to the federal corporate income tax rate, a partial limitation on the deductibility of business interest expense, a limitation on the deductibility of certain director and officer compensation expense, limitations on net operating loss carrybacks and carryovers and changes relating to the scope and timing of U.S. taxation on earnings from international business operations. In addition, other changes could be enacted in the future to increase the corporate tax rate, limit further the deductibility of interest, or effect other changes that could have a material adverse effect on our financial condition. Such changes could also include increases in state taxes and other changes to state tax laws to replenish state and local government finances depleted by costs attributable to the COVID-19 pandemic and the reduction in tax revenues due to the accompanying economic downturn.

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. Changes to tax laws may also adversely affect our ability to attract and retain key personnel.

Item 1B. Unresolved Staff Comments

None.

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, 2022, 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, 2022 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, 2022:

Reserve Category	SEC Pricing Proved Reserves ⁽¹⁾					
	Reserve Volumes				PV-10 ⁽³⁾	
	Oil (MMbbls)	Natural Gas (MMcf)	Total (MBoe) ⁽²⁾	%	Amount (in thousands)	%
Proved developed producing	15,376	89,418	30,279	60%	\$ 1,008,786	65%
Proved developed non-producing	338	1,616	607	1%	21,779	1%
Proved undeveloped	9,780	59,205	19,648	39%	528,558	34%
Total proved	25,494	150,239	50,534	100%	\$ 1,559,123	100%
Total proved developed	15,714	91,034	30,886	61%	\$ 1,030,565	66%

(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, 2022 based on average prices of \$94.14 per barrel of oil and \$6.36 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 \$16.0 million as of December 31, 2022. 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, 2022, 2021 and 2020 to the Standardized Measure of Discounted Future Net Cash Flows.

Standardized Measure Reconciliation

<i>(in thousands)</i>	December 31, 2022
Pre-tax present value of estimated future net revenues (Pre-Tax PV10%)	\$ 1,559,123
Future income taxes, discounted at 10%	(323,197)
Standardized measure of discounted future net cash flows	<u>\$ 1,235,926</u>
<i>(in thousands)</i>	December 31, 2021
Pre-tax present value of estimated future net revenues (Pre-Tax PV10%)	\$ 778,230
Future income taxes, discounted at 10%	(3,879)
Standardized measure of discounted future net cash flows	<u>\$ 774,351</u>
<i>(in thousands)</i>	December 31, 2020
Pre-tax present value of estimated future net revenues (Pre-Tax PV10%)	\$ 197,146
Future income taxes, discounted at 10%	(1,563)
Standardized measure of discounted future net cash flows	<u>\$ 195,583</u>

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, 2022, we had approximately 19,648 MBoe of proved undeveloped reserves as compared to 23,008 MBoe at December 31, 2021. A reconciliation of the change in proved undeveloped reserves during 2022 is as follows:

	MBoe
Estimated proved undeveloped reserves at 12/31/2021	23,008
Extensions and discoveries	7,512
Acquisition of reserves	4,068
Divestiture of reserves	—
Conversion to proved developed reserves	(13,831)
Revisions of previous estimates	(1,109)
Estimated proved undeveloped reserves at 12/31/2022	19,648

- *Extensions and discoveries.* In 2022, proved undeveloped reserves increased by 7,512 MBoe as a result of new proved undeveloped locations added primarily in the Permian and Eagle Ford Basins.
- *Acquisition of Reserves.* In 2022, acquisitions of proved undeveloped reserves of 4,068 MBoe were primarily attributable to the acquisitions of oil and natural gas properties in the Permian Basin. See Note 5 of the Notes to the Consolidated Financial Statements for additional discussion of acquisitions during 2022.
- *Conversion to proved developed reserves.* In 2022, development of oil and natural gas properties resulted in the conversion of 13,831 MBoe from proved undeveloped reserves to proved developed reserves. During the year ended December 31, 2022, we incurred development costs of approximately \$150.7 million related to these locations.
- *Revisions of previous estimates.* In 2022, revisions of previous estimates decreased proved undeveloped reserves by 1,109 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. The decrease was partially offset by an increase in proved undeveloped reserves due to higher 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, 2022, the PV-10 value of our proved undeveloped reserves amounted to 34% 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 65% 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, 2022, estimated future development costs required for the development of proved undeveloped reserves are projected to be approximately \$233.7 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 2022 Reserve Report is Mr. Nathan Shahan. Mr. Shahan, a Licensed Professional Engineer in the State of Texas (No. 102389), has been practicing consulting petroleum engineering at NSAI since 2007 and has over 5 years of prior industry experience. He graduated from Texas A&M University in 2002 with a Bachelor of Science Degree in Petroleum Engineering and in 2007 with a Master of Engineering Degree in Petroleum Engineering. Mr. Shahan meets or exceeds

the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. He is a member of the Society of Petroleum Engineers and Society of Petroleum Evaluation Engineers.

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

The reserves set forth in the NSAI report for the Properties are estimated by performance methods or analogy. In general, reserves attributable to producing wells and/or reservoirs are estimated by performance methods such as decline curve analysis which utilizes extrapolations of historical production data. Reserves attributable to non-producing and undeveloped reserves included in our report are estimated by analogy. The estimates of the reserves, future production, and income attributable to Properties are prepared using widely industry-accepted petroleum economic software packages, as well as NSAI's own proprietary petroleum economic software.

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

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

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

Internal Controls Over Reserves Estimation Process

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

The Manager's technical team meets with our independent third-party engineering firm to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with the Manager's prescribed internal control procedures. The Manager's internal controls over the reserves estimation process includes inter-departmental verification of input data into the Manager's reserves evaluation software such as, but not limited to the following:

- Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in the Manager's reserves database;
- Review of working interests and net revenue interests in the Manager's reserves database against the Manager's well ownership system;
- Review of historical realized prices and differentials from index prices as compared to the differentials used in the Manager's reserves database;
- Review of updated projected capital costs for upcoming projects;
- Review of internal reserve estimates by well and by area by the Manager's reservoir engineers;
- Discussion of material reserve variances among the Manager's reservoir engineer and our executive management; and
- Review of a preliminary copy of the reserve report by our management.

Drilling and Development Activities

The following table sets forth the number of gross and net productive wells drilled in the years ended December 31, 2022, 2021 and 2020. 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. Therefore, drilling activity related to exploratory wells and dry holes was not applicable to us in the years presented below.

	December 31,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net
Productive development wells	265	20.78	213	14.18	113	10.54

At December 31, 2022, we had 147 gross (16.73 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, 2022. A significant majority of our wells in the Permian, Bakken, and DJ Basins, and wells we historically owned in the SCOOP/STACK 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, 2022						
	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian	448	2	450	40.82	0.02	40.84
Eagle Ford	105	81	186	19.08	4.26	23.34
Bakken	907	1	908	37.73	0.20	37.93
Haynesville	—	62	62	—	12.18	12.18
DJ	681	70	751	16.43	2.16	18.59
Total	2,141	216	2,357	114.06	18.82	132.88

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

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

The following table summarizes our cumulative gross and net productive oil and natural gas wells by basin at December 31, 2020:

December 31, 2020						
	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Permian	260	2	262	18.43	0.39	18.82
Eagle Ford	83	70	153	16.03	3.80	19.83
Bakken	831	—	831	35.31	—	35.31
Haynesville	—	50	50	—	8.97	8.97
DJ	—	—	—	—	—	—
SCOOP/STACK	41	8	49	0.60	0.14	0.74
Total	1,215	130	1,345	70.37	13.30	83.67

Developed and Undeveloped Acreage

The following table summarizes our estimated gross and net developed and undeveloped acreage by area at December 31, 2022.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Permian	40,132	5,931	4,486	2,731	44,618	8,662
Eagle Ford	21,355	3,196	11,558	3,302	32,913	6,498
Bakken	169,897	13,167	1,863	1,863	171,760	15,030
Haynesville	3,884	2,298	—	—	3,884	2,298
DJ	23,426	1,822	—	—	23,426	1,822
Total:	258,694	26,414	17,907	7,896	276,601	34,310

Acreage Expirations

As a non-operator, we are subject to lease expirations if an operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage summarized in the table below will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or some other "savings clause" is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have been commenced. While we generally expect to establish production from most of our acreage prior to expiration of the applicable lease terms, there can be no guarantee they can do so. The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2022 by area:

	2023		2024		2025 and Thereafter	
	Gross	Net	Gross	Net	Gross	Net
Permian	—	—	1,845	2,103	2,641	628
Eagle Ford ⁽¹⁾	11,558	3,302	—	—	—	—
Bakken	1,543	1,543	320	320	—	—
Haynesville	—	—	—	—	—	—
DJ	—	—	—	—	—	—
Total:	<u>13,101</u>	<u>4,845</u>	<u>2,165</u>	<u>2,423</u>	<u>2,641</u>	<u>628</u>

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

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

Recent Acquisitions

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

Item 3. Legal Proceedings

Our Company was not a party to any material legal proceedings during the year ended December 31, 2022. 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 Purchases of Equity Securities

Market Information

Our common stock and warrants are listed and traded on the New York Stock Exchange under the symbols "GRNT" and "GRNT.WS," respectively.

As of March 22, 2023, there were 76 holders of record of our common stock and one holder of record of our warrants.

Dividend Policy

During the fourth quarter of 2022, our Board of Directors declared a dividend of \$0.08 per share of our common stock. The dividend was payable on December 15, 2022 to stockholders of record on December 1, 2022. The initial common dividend was prorated to October 24, 2022, the effective date of our Business Combination, which equaled \$0.08 per common share for the quarter. On February 21, 2023, our Board of Directors declared a cash dividend of \$0.11 per share for the first quarter of 2023 that was paid on March 15, 2023 to stockholders of record as of March 1, 2023.

The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board of Directors. Our Board of Directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions (including restrictions under our Credit Agreement), restrictions imposed by applicable law and other factors that the Board of Directors deems relevant at the time of such determination.

Repurchases of Equity Securities

In December 2022, the Company announced that its Board of Directors approved a share repurchase program for up to \$50.0 million of the Company's common stock through December 31, 2023. Under the stock repurchase program, the Company will repurchase shares of its common stock from time to time in open market transactions or in privately negotiated transactions as permitted under applicable rules and regulations. The Board of Directors of the Company may limit or terminate the stock repurchase program at any time without prior notice, but, with no further action of the Board of Directors of the Company, the stock repurchase program will terminate on December 31, 2023.

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

Period	Total number of shares purchased	Average price paid per share	Total number of shares purchased as part of publicly announced plans	Approximate dollar value of shares that may yet be purchased under the plans or programs (in millions)
October 1, 2022 - October 31, 2022	—	—	—	—
November 1, 2022 - November 30, 2022	—	—	—	—
December 1, 2022 - December 31, 2022	25,920	\$ 8.80	25,920	\$49.8

Item 6. [RESERVED]

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

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

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

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

Overview

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

As of December 31, 2022, we owned an interest in 2,357 gross (132.88 net) producing wells, 258,694 gross (26,414 net) developed acres, and 17,907 gross (7,896 net) undeveloped acres, all located in the United States.

Our average daily production for the year ended December 31, 2022 was 19,765 Boe per day.

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

Business Combination

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

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

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

Impacts of COVID-19 Pandemic and Geopolitical Factors

The global spread of COVID-19 since early 2020 has created significant market volatility and economic uncertainty and disruption. The virus created unprecedented challenges for our industry, including a drastic decline in demand for crude oil and natural gas. This, combined with OPEC actions in early 2020, led to spot and future prices of crude oil falling to historic lows during the second quarter of 2020 and remaining depressed through much of 2020. Conditions have significantly improved with the increase in domestic vaccination programs and reduced spread of the COVID-19 virus overall, which have contributed to an improvement in the economy and higher realized prices for commodities since the beginning of 2021.

On February 24, 2022, a large-scale military invasion of Ukraine by Russian troops was reported. Although the length and impact of the ongoing military conflict is highly unpredictable, the conflict in Ukraine has led and could lead to significant market and other disruptions, including significant volatility in commodity prices, and supply of energy resources, instability in credit and capital markets, supply chain interruptions, political and social instability, changes in consumer or purchaser preferences as well as increase in cyberattacks and espionage. Various of Russia's actions have led to sanctions and other penalties being levied by the U.S., the European Union, and other countries, as well as other public and private actors and companies, against Russia and certain other geographic areas, including agreement to remove certain Russian financial institutions from the SWIFT payment system, expansive bans on imports and exports of products to and from Russia (including imports of Russian oil, liquefied natural gas and coal) and a ban on exportation of U.S. denominated banknotes to Russia or persons located therein. These disruptions in the oil and gas markets have caused, and could continue to cause, significant volatility in energy prices, which could have a material effect on our business. Additional potential sanctions and penalties have also been proposed and/or threatened.

While we use derivative instruments to partially mitigate the impact of commodity price volatility on revenues, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas. In addition, because our property interests are not operated by us, we have limited ability to influence or control the future development of such properties. In light of the current price and economic environment, we continue to be proactive with third-party operators to review spending and alter plans as appropriate. We expect that our cash flow from operations and borrowing availability under our credit facilities will allow us to meet our liquidity needs for at least the next 12 months.

Source of Our Revenues

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

instruments to hedge future sales prices on a portion of our oil and natural gas production. We expect our derivative activities will help us achieve more predictable cash flows and reduce our exposure to downward price fluctuations. The use of derivative instruments has in the past, and may in the future, prevent us from realizing the full benefit of upward price movements but also mitigates the effects of declining price movements.

Principal Components of Our Cost Structure

Lease operating expenses

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

Production and ad valorem taxes

Production taxes are paid on produced oil and natural gas. Ad valorem taxes are paid on the value of our properties in certain states. We seek to take full advantage of all credits and exemptions in our various taxing jurisdictions. In general, the production taxes we pay correlate to the changes in oil and natural gas revenues.

Depletion and accretion expense

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

Impairment expense

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

General and administrative expenses

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

Interest expense

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

Gain (loss) on derivative contracts

We utilize commodity derivative financial instruments to reduce our exposure to fluctuations in the prices of oil and natural gas. Gain (loss) on derivative contracts is comprised of (i) cash gains and losses we recognize on settled commodity

derivatives during the period, and (ii) non-cash mark-to-market gains and losses we incur on commodity derivative instruments outstanding at period-end.

Selected Factors That Affect Our Operating Results

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

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

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

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

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

Our oil price differential to the NYMEX benchmark price during 2022, 2021 and 2020 was \$(1.89) per barrel, \$(5.00) per barrel and \$(1.94) per barrel, respectively. Our natural gas price differential during 2022, 2021 and 2020 was \$0.91 per Mcf, \$1.32 per Mcf and \$(0.55) 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. World-wide 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, 2022, 2021 and 2020.

	December 31,		
	2022	2021	2020
Average NYMEX Prices (1)			
Oil (per Bbl)	\$ 94.39	\$ 68.07	\$ 39.34
Natural gas (per Mcf)	6.55	3.72	2.13

(1) Based on average NYMEX closing prices.

The average 2022 NYMEX oil pricing was \$94.39 per barrel of oil or 39% higher than the average NYMEX price per barrel in 2021. Our settled derivatives decreased our realized oil price per barrel by \$6.48 in 2022 and by \$5.58 in 2021. Our average 2022 realized oil price per barrel after reflecting settled derivatives was \$86.02 compared to \$57.49 in 2021. The average 2022 NYMEX natural gas pricing was \$6.55 per Mcf, or 76% higher than the average NYMEX price per Mcf in 2021. Our settled derivatives decreased our realized natural gas price per Mcf by \$0.88 in 2022 and by \$0.42 in 2021. Our average 2022 realized gas price per Mcf after reflecting settled derivatives was \$6.58 compared to \$4.62 in 2021.

The average 2021 NYMEX oil pricing was \$68.07 per barrel of oil or 73% higher than the average NYMEX price per barrel in 2020. Our settled derivatives decreased our realized oil price per barrel by \$5.58 in 2021 and increased our realized oil price per barrel by \$5.37 in 2020. Our average 2021 realized oil price per barrel after reflecting settled derivatives was \$57.49 compared to \$42.77 in 2020. The average 2021 NYMEX natural gas pricing was \$3.72 per Mcf, or 75% higher than the average NYMEX price per Mcf in 2020. Our settled derivatives decreased our realized natural gas price per Mcf by \$0.42 in 2021 and increased it by \$0.17 in 2020. Our average 2021 realized gas price per Mcf after reflecting settled derivatives was \$4.62 compared to \$1.75 in 2020.

Results of Operations

Year ended December 31, 2022 compared to year ended December 31, 2021

The following table sets forth summary production and operating data for the periods indicated. 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,	
	2022	2021
Net Sales (in thousands):		
Oil sales	\$ 338,163	\$ 215,250
Natural gas and related product sales	159,254	74,943
Revenues	497,417	290,193
Net Production:		
Oil (MBbl)	3,656	3,413
Natural gas (MMcf)	21,351	14,861
Total (MBoe) ⁽¹⁾	7,215	5,890
Average Daily Production:		
Oil (Bbl)	10,016	9,351
Natural gas (Mcf)	58,496	40,715
Total (Boe) ⁽¹⁾	19,765	16,137
Average Sales Prices:		
Oil (per Bbl)	\$ 92.50	\$ 63.07
Effect of loss on settled oil derivatives on average price (per Bbl)	(6.48)	(5.58)
Oil net of settled oil derivatives (per Bbl)	86.02	57.49
Natural gas and related product sales (per Mcf)	7.46	5.04
Effect of loss on settled natural gas derivatives on average price (per Mcf)	(0.88)	(0.42)
Natural gas and related product sales net of settled natural gas derivatives (per Mcf)	6.58	4.62
Realized price on a Boe basis excluding settled commodity derivatives	68.94	49.27
Effect of loss on settled commodity derivatives on average price (per Boe)	(5.88)	(4.28)
Realized price on a Boe basis including settled commodity derivatives	63.06	44.99
Operating Expenses (in thousands):		
Lease operating expenses	\$ 44,678	\$ 26,333
Production and ad valorem taxes	30,619	18,066
Depletion and accretion expense	105,752	94,661
General and administrative	14,223	10,179
Costs and Expenses (per Boe):		
Lease operating expenses	\$ 6.19	\$ 4.47
Production and ad valorem taxes	4.24	3.07
Depletion and accretion	14.66	16.07
General and administrative	1.97	1.73
Net Producing Wells at Period-End:	132.88	108.64

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

Oil, Natural Gas and Related Product Sales

Our revenues vary from year to year primarily due to changes in realized commodity prices and production volumes. In 2022, our oil and natural gas sales increased 71% from 2021, driven by an increase in realized prices, excluding the effect of settled commodity derivatives, and an increase in production volumes. The higher average price in 2022 as compared to 2021 was driven by higher average NYMEX oil and natural gas prices.

Realized production from oil and gas properties increased because of drilling success and the acquisition of additional net revenue interests. This increase in production is offset by the natural decline of the production rate of existing oil and natural gas wells. The number of wells we participated in increased from 108.64 net wells in 2021 to 132.88 net wells in 2022.

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

	Year Ended December 31,	
	2022	2021
Net Production:		
Oil (MBbl)		
Permian	2,347	1,961
Eagle Ford	467	422
Bakken	616	778
Haynesville	—	—
DJ	226	236
SCOOP/STACK	—	16
Total	3,656	3,413
Natural Gas (MMcf)		
Permian	5,957	5,019
Eagle Ford	2,001	1,705
Bakken	1,101	1,798
Haynesville	10,161	3,460
DJ	2,131	2,759
SCOOP/STACK	—	120
Total	21,351	14,861
Total (MBoe)		
Permian	3,339	2,797
Eagle Ford	801	706
Bakken	800	1,078
Haynesville	1,694	577
DJ	581	696
SCOOP/STACK	—	36
Total	7,215	5,890

Lease Operating Expenses

Lease operating expenses were \$44.7 million in 2022 compared to \$26.3 million in 2021. On a per unit basis, lease operating expenses increased 38% from \$4.47 per Boe in 2021 to \$6.19 per Boe in 2022. On an absolute dollar basis, the increase in our lease operating expenses in 2022 compared to 2021 was primarily due to an increase in well count due to acquisitions and additional wells successfully drilled and completed, higher transportation and gathering expenses related to certain take-in kind arrangements and overall increased cost of services. Transportation and gathering expenses related to certain take-in kind arrangements increased from \$0.9 million in 2021 to \$5.6 million in 2022. The increase in lease operating expenses per Boe was primarily due to the increase in lease operating expenses noted above, partially offset by an increase in production.

Production and Ad Valorem Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were \$26.9 million in 2022 compared to \$17.1 million in 2021. As a percentage of oil and natural gas sales, our production taxes were 5% and 6% in 2022 and 2021, respectively. The fluctuation in our average production tax rate from year to year is primarily due to

changes in our oil sales as a percentage of our total oil and natural gas sales and the mix of our production volumes by basin. However, production taxes as a percent of total oil and natural gas sales are consistent with historical trends.

Ad valorem taxes increased by \$2.7 million during the year ended December 31, 2022 as compared to the year ended December 31, 2021, primarily due to additional wells drilled and completed and new wells acquired.

Depletion and Accretion

Depletion and accretion was \$105.8 million in 2022 compared to \$94.7 million in 2021. Depletion and accretion was \$14.66 per Boe in 2022 compared to \$16.07 per Boe in 2021. The aggregate increase in depletion and accretion expense for 2022 compared to 2021 was driven by the increase in depletion expense primarily due to the increase in production, partially offset by the decrease in the depletion rate per Boe.

General and Administrative

General and administrative expenses were \$14.2 million in 2022 compared to \$10.2 million in 2021. The increase was primarily due to higher management fees and higher professional services and legal costs. Management fees were \$7.9 million in 2022 compared to \$6.2 million in 2021. See Note 10 in the Notes to the Consolidated Financial Statements for additional information on management fees.

Gain on Disposal of Oil and Natural Gas Properties

We did not recognize a gain on disposal of oil and natural gas properties in 2022. We recognized a gain on disposal of oil and natural gas properties of \$2.3 million in 2021, primarily due to the sale of certain Permian Basin assets, the sale of a partial unit in the Bakken Basin and the sale of a unit in the SCOOP/STACK Basin.

Gain/(Loss) on Derivatives – Commodity Derivatives

The following table sets forth the loss on derivatives for the years ended December 31, 2022 and 2021:

(in thousands)	Year Ended December 31,	
	2022	2021
Loss on commodity derivatives:		
Oil derivatives	\$ (14,985)	\$ (24,885)
Natural gas derivatives	(10,339)	(7,504)
Total	<u>\$ (25,324)</u>	<u>\$ (32,389)</u>

The following table represents our net cash payments on derivatives for the years ended December 31, 2022 and 2021:

(in thousands)	Year Ended December 31,	
	2022	2021
Net payments on commodity derivatives:		
Oil derivatives	\$ (23,695)	\$ (19,034)
Natural gas derivatives	(18,742)	(6,185)
Total	<u>\$ (42,437)</u>	<u>\$ (25,219)</u>

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 \$2.0 million in 2022 compared to \$2.4 million in 2021. The decrease in interest expense was primarily due to lower average outstanding balance on the revolving credit facilities during 2022 as compared to 2021.

Gain on Derivatives – Common Stock Warrants

We recognized a gain of \$0.4 million during 2022 from the change in fair value of the warrant liability. See Note 3 in the Notes to the Consolidated Financial Statements for additional information on the common stock warrants.

Income Tax Expense (Benefit)

We recognized an income tax expense of \$12.9 million in 2022. There was no income tax expense (benefit) in 2021. The change in income tax expense during the year ended December 31, 2022, compared with 2021, was due to the fact that the Funds were treated as partnerships for U.S. federal income tax purposes and, as such, the partners of the Funds reported their share of the Fund's income or loss on their respective income tax returns. In contrast, Granite Ridge is a corporation for U.S. federal income tax purposes and is subject to U.S. federal income taxes on any income or loss from the operation of the Company's assets following the Business Combination on October 24, 2022. The effective income tax rate differs from the statutory rate primarily due to the allocation of profits and losses to the partners of the Funds for the period prior to the Business Combination. See Note 7 to the Notes to the Consolidated Financial Statements for additional discussion of income taxes.

Year ended December 31, 2021 compared to year ended December 31, 2020

The following table sets forth selected operating data for the periods indicated. Average sales prices are derived from accrued accounting data for the relevant period indicated.

	Year Ended December 31,	
	2021	2020
Net Sales (in thousands):		
Oil sales	\$ 215,250	\$ 70,870
Natural gas and related product sales	74,943	16,228
Revenues	290,193	87,098
Net Production:		
Oil (MBbl)	3,413	1,895
Natural gas (MMcf)	14,861	10,294
Total (MBoe) ⁽¹⁾	5,890	3,611
Average Daily Production:		
Oil (Bbl)	9,351	5,178
Natural gas (Mcf)	40,715	28,126
Total (Boe) ⁽¹⁾	16,137	9,866
Average Sales Prices:		
Oil (per Bbl)	\$ 63.07	\$ 37.40
Effect of (loss) gain on settled oil derivatives on average price (per Bbl)	(5.58)	5.37
Oil net of settled oil derivatives (per Bbl)	57.49	42.77
Natural gas and related product sales (per Mcf)	5.04	1.58
Effect of (loss) gain on settled natural gas derivatives on average price (per Mcf)	(0.42)	0.17
Natural gas and related product sales net of settled natural gas derivatives (per Mcf)	4.62	1.75
Realized price on a Boe basis excluding settled commodity derivatives	49.27	24.12
Effect of (loss) gain on settled commodity derivatives on average price (per Boe)	(4.28)	3.30
Realized price on a Boe basis including settled commodity derivatives	44.99	27.42
Operating Expenses (in thousands):		
Lease operating expenses	\$ 26,333	\$ 20,398
Production and ad valorem taxes	18,066	6,663
Depletion and accretion expense	94,661	79,947
Impairment expense	—	5,725
General and administrative	10,179	10,108
Costs and Expenses (per Boe):		
Lease operating expenses	\$ 4.47	\$ 5.65
Production and ad valorem taxes	3.07	1.85
Depletion and accretion	16.07	22.14
General and administrative	1.73	2.80
Net Producing Wells at Period-End:	108.64	83.67

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

Oil, Natural Gas and Related Product Sales

Our revenues vary from year to year primarily as a result of changes in realized commodity prices and production volumes. In 2021, our oil and natural gas sales increased 233% from 2020, driven by an 104% increase in realized prices, excluding the effect of settled commodity derivatives, and a 63% increase in production volumes. The higher average price in 2021 as compared to 2020 was driven by higher average NYMEX oil and natural gas prices.

Realized production from oil and gas properties increases through drilling success and acquisition of additional net revenue interests. This increase in production is offset by the natural decline of the production rate of existing oil and natural gas wells. The number of wells we participated increased from 83.67 net wells in 2020 to 108.64 net wells in 2021.

The following table sets forth information regarding our oil and natural gas production by basin and realized prices for the periods indicated.

	Year Ended December 31,	
	2021	2020
Net Production:		
Oil (MBbl)		
Permian	1,961	900
Eagle Ford	422	258
Bakken	778	727
Haynesville	—	—
DJ	236	—
SCOOP/STACK	16	10
Total	3,413	1,895
Natural Gas (MMcf)		
Permian	5,019	1,618
Eagle Ford	1,705	1,684
Bakken	1,798	1,491
Haynesville	3,460	5,450
DJ	2,759	—
SCOOP/STACK	120	51
Total	14,861	10,294
Total (MBoe)		
Permian	2,797	1,169
Eagle Ford	706	539
Bakken	1,078	976
Haynesville	577	908
DJ	696	—
SCOOP/STACK	36	19
Total	5,890	3,611

Lease Operating Expenses

Lease operating expenses were \$26.3 million in 2021 compared to \$20.4 million in 2020. On a per unit basis, lease operating expenses decreased 26% from \$5.65 per Boe in 2020 to \$4.47 per Boe in 2021 due primarily to higher production volumes over which fixed costs can be spread. On an absolute dollar basis, the 29% increase in our lease operating expenses in 2021 compared to 2020 was primarily due to an increase in well count due to acquisitions and additional wells successfully drilled and completed.

Production and Ad Valorem Taxes

We pay production taxes based on realized oil and natural gas sales. Production taxes were \$17.1 million in 2021 compared to \$6.0 million in 2020. As a percentage of oil and natural gas sales, our production taxes were 6% and 7% in 2021 and 2020, respectively. The fluctuation in our average production tax rate from year to year is primarily due to

changes in our oil sales as a percentage of our total oil and natural gas sales and the mix of our production volumes by basin. However, production taxes as a percent of total oil and natural gas sales are consistent with historical trend.

Ad valorem taxes increased by \$0.3 million during the year ended December 31, 2021 as compared to the year ended December 31, 2020, primarily due to additional wells drilled and completed and new wells acquired.

Depletion and Accretion

Depletion and accretion was \$94.7 million in 2021 compared to \$79.9 million in 2020. Depletion and accretion was \$16.07 per Boe in 2021 compared to \$22.14 per Boe in 2020. The aggregate increase in depletion and accretion expense for 2021 compared to 2020 was driven by a 63% increase in production levels, partially offset by the decrease in the depletion rate per Boe.

Impairments of long-lived assets

We did not record any impairments of oil and natural gas properties in 2021. In 2020, as a result of low commodity prices and their effect on the proved reserve values of our properties, we recorded an impairment of \$5.7 million to our proved oil and natural gas properties.

General and Administrative

General and administrative expenses were \$10.2 million in 2021 compared to \$10.1 million in 2020. General and administrative expense remained materially consistent in 2021 compared to 2020. General and administrative fees include management fees which were \$6.2 million in 2021 compared to \$6.6 million in 2020.

Gain on Disposal of Oil and Natural Gas Properties

We recognized a gain on disposal of oil and natural gas properties of \$2.3 million in 2021 compared to \$0.6 million in 2020. The increase in 2021 was primarily driven by the sale of Permian Basin assets, the sale of a partial unit in the Bakken Basin and the sale of a complete unit in our SCOOP/STACK Basin.

Gain/(Loss) on Derivatives

The following table sets forth the (loss) gain on derivatives for the years ended December 31, 2021 and 2020:

<i>(in thousands)</i>	Year Ended December 31,	
	2021	2020
(Loss) gain on commodity derivatives:		
Oil derivatives	\$ (24,885)	\$ 11,604
Natural gas derivatives	(7,504)	1,402
Total	<u>\$ (32,389)</u>	<u>\$ 13,006</u>

The following table represents our net cash (payments on) receipts from derivatives for the years ended December 31, 2021 and 2020:

<i>(in thousands)</i>	Year Ended December 31,	
	2021	2020
Net cash (payments on) receipts from commodity derivatives:		
Oil derivatives	\$ (19,034)	\$ 10,180
Natural gas derivatives	(6,185)	1,733
Total	<u>\$ (25,219)</u>	<u>\$ 11,913</u>

Our earnings are affected by the changes in 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 \$2.4 million in 2021 compared to \$1.8 million in 2020. The increase in interest expense for 2021 as compared to 2020 was primarily due to an increase in the outstanding balance on the revolving credit facility.

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, 2022, we had no outstanding debt under our Credit Agreement. We had \$200.8 million of liquidity as of December 31, 2022, consisting of \$150.0 million of committed borrowing availability under the Credit Agreement and \$50.8 million of cash on hand.

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 \$10.7 million, or \$0.08 per share during the fourth quarter of 2022. On February 21, 2023, our Board of Directors declared a cash dividend of \$0.11 per share for the first quarter of 2023 that was paid on March 15, 2023 to stockholders of record as of March 1, 2023. 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 million of our common stock through December 31, 2023. Under the stock repurchase program, we will repurchase shares of our common stock from time to time in open market transactions or in privately negotiated transactions as permitted under applicable rules and regulations. The Board of Directors of the Company may limit or terminate the stock repurchase program at any time without prior notice, but, with no further action of the Board of Directors of the Company, the stock repurchase program will terminate on December 31, 2023.

As of December 31, 2022, we had repurchased 25,920 shares under the program at an aggregate cost of \$0.2 million. The extent to which we repurchase our shares of common stock, and the timing of such repurchases, will depend upon market conditions and other considerations as may be considered in our sole discretion.

Cash Flows

Our cash flows for the years ended December 31, 2022, 2021 and 2020 are presented below:

(in thousands)	Year Ended December 31,		
	2022	2021	2020
Net cash provided by operating activities	\$ 346,389	\$ 181,181	\$ 66,806
Net cash used in investing activities	(230,562)	(186,024)	(116,743)
Net cash (used in) provided by financing activities	(76,848)	8,489	52,071
Net change in cash	<u>\$ 38,979</u>	<u>\$ 3,646</u>	<u>\$ 2,134</u>

Cash Flows from Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which are the volatility of prices for oil and natural gas and the volume of oil and natural gas sold by our producers. Any interim cash needs are funded by cash on hand, cash flows from operations or borrowings under our Credit Agreement.

Net cash provided by operating activities in 2022 was \$346.4 million, compared to \$181.2 million in 2021. The increase in net cash provided by operating activities was primarily due to an increase in total operating revenues attributable to an increase in production and higher realized oil and natural gas prices. The increase was partially offset by higher settlements paid on commodity derivatives and higher operating expense. We paid \$42.4 million of settlements on commodity derivatives during 2022 as compared to \$25.2 million during 2021.

Our net cash provided by operating activities included a reduction of \$17.2 million and \$26.9 million for the years ended December 31, 2022 and 2021, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

Net cash provided by operating activities in 2021 was \$181.2 million, compared to \$66.8 million in 2020. The increase in net cash provided by operating activities was primarily due to an increase in total operating revenues attributable to an increase in production and higher realized oil and natural gas prices. The increase was partially offset by \$25.2 million of settlements paid on commodity derivatives during 2021 as compared to \$11.9 million of cash receipts during 2020.

Our net cash provided by operating activities included a reduction of \$26.9 million and a benefit of \$6.7 million for the years ended December 31, 2021 and 2020, respectively, associated with changes in working capital items.

Cash Flows from Investing Activities

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

For the year ended December 31, 2021, our net cash used in investing activities was \$186.0 million, which consisted primarily of our investment of \$136.1 million of additions to oil and natural gas properties and \$83.2 million of acquisitions of oil and natural gas properties, partially offset by \$29.4 million of proceeds received from the disposition of certain oil and natural gas assets.

For the year ended December 31, 2020, our net cash used in investing activities was \$116.7 million, which consisted primarily of our investment of \$99.5 million of additions to oil and natural gas properties and \$17.9 million of acquisitions of oil and natural gas properties.

Cash Flows from Financing Activities

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

For the years ended December 31, 2021 and 2020, our net cash provided from financing activities was \$8.5 million and \$52.1 million, respectively. Net cash provided from financing activities in these years was primarily related to partners' contributions and proceeds from borrowings on our credit facilities, partially offset by repayments of borrowings and partners' distributions.

Granite Ridge Credit Agreement

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

The Credit Agreement provides for aggregate elected commitments of \$150.0 million, an initial borrowing base of \$325.0 million and an aggregate maximum revolving credit amount of \$1,000.0 million. The borrowing base is scheduled to be redetermined semiannually on or about April 1 and October 1 of each calendar year, commencing April 1, 2023, 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. Additionally, each of 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 we are able to borrow under the Credit Agreement is subject to compliance with the financial covenants, satisfaction of various conditions precedent to borrowing and other provisions of the Credit Agreement.

As of December 31, 2022, we did not have any borrowings or letters of credit outstanding under the Credit Agreement, resulting in availability of \$150.0 million. The Credit Agreement is guaranteed by our restricted subsidiaries and is secured by a first priority mortgage and security interest in substantially all of our assets and our restricted subsidiaries.

Borrowings under the Credit Agreement may be base rate loans or secured overnight financing rate ("SOFR") loans. Interest is payable quarterly for base rate loans and at the end of the applicable interest period for SOFR loans. SOFR loans bear interest at SOFR plus an applicable margin ranging from 250 to 350 basis points, depending on the percentage of the borrowing base utilized, plus an additional 10, 15 or 20 basis point credit spread adjustment for a one, three or six month interest period, respectively. Base rate loans 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 an applicable margin ranging from 150 to 250 basis points, depending on the percentage of the borrowing base utilized. We also pay a commitment fee on unused elected commitment amounts under its facility of 50 basis points. We may repay any amounts borrowed under the Credit Agreement prior to the maturity date without any premium or penalty.

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

- (i) a current ratio, which is the ratio of our consolidated current assets (including unused commitments under the Credit Agreement and excluding non-cash asset retirement and derivative assets) to our consolidated current liabilities (excluding the current portion of long-term debt under the Credit Agreement and non-cash asset retirement and derivative liabilities), of not less than 1.00 to 1.00; and

- (ii) a leverage ratio, which is the ratio of Consolidated Total Debt to EBITDAX (each as defined in the Credit Agreement), subject to certain adjustments, of not greater than 3.00 to 1.00.

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, 2022, we were in compliance with all covenants required by the Credit Agreement

Known Contractual and Other Obligations; Planned Capital Expenditures

Contractual and Other Obligations

On October 24, 2022, the Funds terminated their revolving credit facilities, and we entered into a new credit agreement. As of December 31, 2022, there was no outstanding balance on the Credit Agreement. See Note 8 of the Notes to the Consolidated Financial Statements. We entered into the MSA with the Manager in which we will pay the Manager an annual services fee of \$10.0 million and will reimburse the Manager for certain Granite Ridge group costs related to the operation of our oil and gas assets and other properties. See Note 10 of the Notes to the Consolidated Financial Statements. We have contractual commitments that may require us to make payments upon future settlement of our commodity derivative contracts. See Note 3 of the Notes to the Consolidated Financial Statements. We have future obligations related to the abandonment of our oil and natural gas properties. See Note 6 of the Notes to the Consolidated Financial Statements. With respect to all of these items, except for our commitments under our debt agreements, we cannot determine with accuracy the amount and/or timing of such payments.

Planned Capital Expenditures

For 2023, we are budgeting approximately \$260 million to \$270 million in total planned capital expenditures, including approximately \$46 million of acquisitions of oil and natural gas properties. We expect to fund planned capital expenditures with cash generated from operations and, if required, borrowings under our Credit Agreement.

The amount, timing and allocation of capital expenditures are largely discretionary and subject to change based on a variety of factors. If oil and natural gas prices decline below our acceptable levels, or costs increase above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We will carefully monitor and may adjust our projected capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, contractual obligations, internally generated cash flow, and other factors both within and outside our control.

Satisfaction of Our Cash Obligations for the Next Twelve Months

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

Effects of Inflation and Pricing

The oil and natural gas industry is typically very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion.

Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. Higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Critical Accounting Estimates

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

Use of Estimates

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

Oil and Natural Gas Reserves

The determination of depletion and amortization expense as well as impairments that are recognized on our oil and natural gas properties are highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. Our estimate of proved reserves is based on the quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in the future years from known reservoirs under existing economic and operating conditions. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation, and judgment. For example, we must estimate the amount and timing of future operating costs, production taxes and development costs, all of which may in fact vary considerably from actual results. In addition, as the prices of oil and natural gas and cost levels change from year to year, the economics of producing our reserves may change and therefore the estimate of proved reserves may also change. As of December 31, 2022, approximately 39% 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 furnish them with the following information that they review: (1) technical support data, (2) technical analysis of geologic and engineering support information, (3) economic and production data and (4) our well ownership interests. 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, 2022.

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 and accretion of oil and natural gas producing properties is determined using the units-of-production method. During the years ended December 31, 2022, 2021 and 2020, we recognized depletion and accretion expense of \$105.8 million, \$94.7 million and \$79.9 million, respectively.

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

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

Impairment of Oil and Natural Gas Properties

All of our long-lived assets are monitored for potential impairment annually, or when circumstances indicate that the carrying value of an asset may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves, risk-adjusted probable and possible reserves, and integrated assets. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates, cash flows from integrated assets and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. At December 31, 2022, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2023 price of \$79.12 per barrel of oil decreasing to a 2027 price of \$64.14 per barrel of oil. Natural gas prices ranged from a 2023 price of \$4.26 per Mcf of natural gas increasing to a 2027 price of \$4.50 per Mcf. Both oil and natural gas commodity prices for this purpose were held flat after 2027.

In March 2020, crude oil demand experienced significant declines due to the COVID-19 pandemic and resulting governmental led shut-downs in economic activity. During 2020, as it became apparent that the pandemic would continue with sustained significant decline in crude oil prices, we assessed our proved oil and natural gas properties for impairment and recorded impairment expense of \$5.7 million during the year ended December 31, 2020. We did not incur any

impairment expense related to our proved oil and natural gas properties during the years ended December 31, 2022 and 2021.

Unproved oil and natural gas properties are assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. The Company did not recognize an impairment expense for the years ended December 31, 2022, 2021 and 2020 related to its unproved oil and natural gas properties.

Derivative Instruments – Commodity Derivatives

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

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

Asset Retirement Obligations

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

Revenue Recognition

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

Recently Issued or Adopted Accounting Pronouncements

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

Off-Balance Sheet Arrangements

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

Item 7A. Quantitative and Qualitative Disclosure about Market Risk

Commodity Price Risk

We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on our earnings. For the year ended December 31, 2022, a 10% increase in average commodity prices would have decreased the fair value of commodity derivatives by \$7.8 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, 2022, 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 no indebtedness under the Credit Agreement at December 31, 2022.

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, 2022.

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

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.

In the preparation of this Annual Report on Form 10-K, we identified errors in the depletion calculation and that certain acquisitions, initially classified as acquisitions of proved oil and natural gas properties, that should have been classified as unproved oil and natural gas properties. The associated errors caused depletion expense and accumulated depletion to be overstated and resulted in the restatement (the "Restatement") of our previously filed unaudited condensed combined financial statements as of and for the three and nine month periods ended September 30, 2022 (the "Subject Periods"). On March 10, 2023, the Company filed with the SEC Amendment No. 1 on Form 10-Q/A to amend and restate the Company's unaudited condensed combined financial statements to reflect the correction of the depletion expense and accumulated depletion of the Company. The Form 10-Q/A also disclosed a related material weakness identified by management in connection with the Restatement (as described below). In the period since the March 10, 2023 filing, management identified additional material weaknesses in Information Technology General Controls ("ITGC") related to access to perform key duties within the financial systems. As a result of these material weaknesses, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) were not effective as of December 31, 2022.

In light of these material weaknesses, management completed additional procedures and analysis to validate the accuracy and completeness of the reported financial results. Notwithstanding these material weaknesses, based on the additional procedures and analysis, management concluded that the consolidated financial statements included in this Annual Report on Form 10-K fairly present in all material respects financial position, results of operations, and cash flows for the periods presented, in conformity with U.S. GAAP.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over our financial reporting. This Annual Report on Form 10-K does not include a report of management's assessment regarding internal control over financial reporting, as allowed by the SEC for reverse acquisitions between an issuer and a private operating company when it is not possible to conduct an assessment of the private operating company's internal control over financial reporting in the period between the consummation date of the reverse acquisition and the date of management's assessment of internal control over financial reporting (pursuant to Section 215.02 of the SEC Division of Corporation Finance's Regulation S-K Compliance & Disclosure Interpretations).

As discussed elsewhere in this Annual Report on Form 10-K, we completed the Business Combination on October 24, 2022. Prior to the Business Combination, Granite Ridge Resources, Inc. was a privately held company with no operations, formed to be the successor following the Business Combination. Its Predecessor, Fund III, was a privately held operating company, and therefore the controls of Granite Ridge Resources, Inc. and the Predecessor were not required to be designed or maintained in accordance with Exchange Act Rule 13a-15. The design of public company internal controls over financial reporting for the Company following the Business Combination has required and will continue to require significant time and resources from our management and other personnel. Furthermore, Executive Network Partnering Corporation, the legal acquirer in the Business Combination, was a non-operating public shell company prior to the Business Combination, and as such the disclosure controls and procedures and internal controls of Executive Network Partnering Corporation no longer exist as of the assessment date. As a result, management was unable, without incurring unreasonable effort or expense to conduct an assessment of our internal control over financial reporting as of December 31, 2022.

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.

Material Weakness in Internal Control over Financial Reporting

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

Management has identified a material weakness related to the lack of effectively designed controls over proper review of the depletion calculation and the accounting for acquisitions and the related allocation and classification of consideration paid for proved and unproved properties. The associated errors caused depletion expense and accumulated depletion to be overstated and resulted in the restatement of our previously filed unaudited condensed combined financial statements as of and for the Subject Periods. Additionally, the material weakness could result in a material misstatement of depletion expense and accumulated depletion that would result in a material misstatement to the annual or interim consolidated financial statements of Granite Ridge Resources, Inc. that would not be prevented or detected.

In addition, management has identified a material weakness related to the lack of effective controls over ITGC pertaining to user access management over systems that support the Company’s financial reporting process. Specifically, it was found that adequate restrictions were not in place to ensure appropriate segregation of duties among our personnel. If the user access material weakness is not remediated, it could result in a material misstatement to the annual or interim consolidated financial statements of Granite Ridge Resources, Inc. that would not be prevented or detected.

Changes in Internal Control over Financial Reporting

As described above, the design and implementation of internal control over financial reporting for the Company following the Business Combination has required and will continue to require significant time and resources from management and other personnel. In preparation for the Business Combination, we have been engaged in the process of the design and implementation of our internal control over financial reporting in a manner commensurate with the scale of our operations post-Business Combination. Changes that have been implemented leading up to and since the time of the Business Combination have included, among other things, the addition of entity level controls, appointment of an Audit Committee, adoption of committee charters and various governance policies, addition of a Chief Accounting Officer with public company experience and establishment of an internal audit function.

In response to the material weaknesses identified as described above, management is in the process of implementing remediation steps to address the material weaknesses and to improve our internal control over financial reporting. Management is committed to the remediation of the material weaknesses described above, as well as the continued improvement of our internal controls over financial reporting.

Except as described above, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) during the fourth quarter of 2022 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations of Controls

Management does not expect that our disclosure controls and procedures or our internal control over financial reporting will prevent or detect all errors and all fraud. Controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving their objectives and management necessarily applies its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of a simple error or mistake. Additionally, controls can be

circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or deterioration in the degree of compliance with the policies or procedures. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Item 9B. Other Information

None.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2022.

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, 2022.

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, 2022.

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, 2022.

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, 2022.

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, 2022 and 2021

Consolidated Statements of Operations for the Years Ended December 31, 2022, 2021 and 2020

Consolidated Statements of Cash Flows for the Years Ended December 31, 2022, 2021 and 2020

Consolidated Statements of Stockholders Equity for the Years Ended December 31, 2022, 2020 and 2019

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).
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
4.2	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Granite Ridge Resources, Inc.'s Registration Statement on Form S-4/A, filed with the SEC on September 12, 2022).
4.3	Specimen Warrant Certificate (incorporated by reference to Exhibit 4.3 to Executive Network Partnering Corporation's Registration Statement on Form S-1, filed with the SEC on September 14, 2020).
4.4	Warrant Agreement, dated September 15, 2020 between Continental Stock Transfer & Trust Company and Executive Network Partnering Corporation (incorporated by reference to Exhibit 4.1 to Executive Network Partnering Corporation's Current Report on Form 8-K, filed with the SEC on September 21, 2020).
4.5	Amendment No. 1 to Warrant Agreement, dated March 24, 2021 between Continental Stock Transfer & Trust Company and Executive Network Partnering Corporation (incorporated by reference to Exhibit 1.01 to Executive Network Partnering Corporation's Current Report on Form 8-K, filed with the SEC on March 25, 2021).
4.6	Assignment, Assumption and Amendment Agreement, dated October 24, 2022 by and among Executive Network Partnering Corporation, Granite Ridge Resources, Inc. and Continental Stock Transfer & Trust Company and Granite Ridge Resources, Inc. (incorporated by reference to Exhibit 4.5 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.1	Registration Rights Agreement and Lock-Up Agreement, dated October 24, 2022 by and among Granite Ridge Resources, Inc., ENPC Holdings II, LLC and the other Holders (as defined therein) listed thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).

Exhibit No.	Description
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	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).
10.5	Sponsor Agreement, dated as of May 16, 2022, by and among ENPC Holdings, LLC, ENPC Holdings II, LLC, Executive Network Partnering Corporation, Granite Ridge Resources, Inc., GREP Holdings, LLC and certain other parties thereto (incorporated by reference to Annex D of Granite Ridge Resources, Inc.'s Registration Statement on Form S-4, filed with the SEC on May 16, 2022).
10.6	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).
10.7	Form of Indemnity Agreement for Officers and Outside Directors (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
10.8#	Executive Employment Agreement between Luke C. Brandenburg 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).
10.9#	Executive Employment Agreement between Tyler S. Farquharson and Granite Ridge Resources, Inc., dated October 24, 2022 (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K filed with the SEC on October 28, 2022).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of FORVIS, LLP (formerly BKD, 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).
99.1*	Reserve Report of Granite Ridge Resources as of December 31, 2022.
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 27, 2023

By: /s/ LUKE C. BRANDENBERG

Name: Luke C. Brandenberg

Title: *President and Chief Executive Officer*

March 27, 2023

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
<u>/s/ Luke C. Brandenberg</u> Luke C. Brandenberg	President and Chief Executive Officer (Principal Executive Officer)	March 27, 2023
<u>/s/ Tyler S. Farquharson</u> Tyler S. Farquharson	Chief Financial Officer (Principal Financial Officer)	March 27, 2023
<u>/s/ Zoran Durkovic</u> Zoran Durkovic	Chief Accounting Officer (Principal Accounting Officer)	March 27, 2023
<u>/s/ Matt Miller</u> Matt Miller	Director and Co-Chairman of the Board	March 27, 2023
<u>/s/ Griffin Perry</u> Griffin Perry	Director and Co-Chairman of the Board	March 27, 2023
<u>/s/ Amanda N. Coussens</u> Amanda N. Coussens	Director	March 27, 2023
<u>/s/ Thaddeus Darden</u> Thaddeus Darden	Director	March 27, 2023
<u>/s/ Michele J. Everard</u> Michele J. Everard	Director	March 27, 2023
<u>/s/ Kirk Lazarine</u> Kirk Lazarine	Director	March 27, 2023
<u>/s/ John McCartney</u> John McCartney	Director	March 27, 2023

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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, 2022 and 2021, 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, 2022, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2022, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits.

We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

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

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

/s/ FORVIS, LLP

(Formerly, BKD, LLP)

We have served as the Company's auditor since 2015.

Dallas, Texas

March 27, 2023

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2022 AND 2021

(in thousands, except par value and share data)	December 31,	
	2022	2021
ASSETS		
Current assets:		
Cash	\$ 50,833	\$ 11,854
Revenue receivable	72,287	47,298
Advances to operators	8,908	37,817
Prepaid and other expenses	4,203	676
Derivative assets - commodity derivatives	10,089	434
Total current assets	146,320	98,079
Property and equipment:		
Oil and gas properties, successful efforts method	1,028,662	727,547
Accumulated depletion	(383,673)	(278,773)
Total property and equipment, net	644,989	448,774
Long-term assets:		
Derivative assets - commodity derivatives	—	31
Other long-term assets	3,468	362
Total long-term assets	3,468	393
TOTAL ASSETS	\$ 794,777	\$ 547,246
LIABILITIES AND EQUITY		
Current liabilities:		
Accrued expenses	\$ 62,180	\$ 10,321
Other liabilities	1,523	13
Derivative liabilities - commodity derivatives	431	7,263
Current portion of long-term debt	—	50,000
Total current liabilities	64,134	67,597
Long-term liabilities:		
Long-term debt	—	1,100
Derivative liabilities - commodity derivatives	—	657
Derivative liabilities - common stock warrants	11,902	—
Asset retirement obligations	4,745	2,962
Deferred tax liability	91,592	—
Total long-term liabilities	108,239	4,719
TOTAL LIABILITIES	172,373	72,316
Commitments and contingencies (Note 11)		
EQUITY:		
Partnerships' capital	—	474,930
Common stock, \$0.0001 par value, 431,000,000 shares authorized, 133,294,897 issued at December 31, 2022.	13	—
Additional paid-in capital	590,232	—
Retained earnings	32,388	—
Treasury stock, at cost, 25,920 shares at December 31, 2022	(229)	—
Total equity	622,404	474,930
TOTAL LIABILITIES AND EQUITY	\$ 794,777	\$ 547,246

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

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2022, 2021 AND 2020

<i>(in thousands, except per share data)</i>	Year Ended December 31,		
	2022	2021	2020
REVENUES			
Oil, natural gas and related product sales	\$ 497,417	\$ 290,193	\$ 87,098
EXPENSES			
Lease operating expenses	44,678	26,333	20,398
Production and ad valorem taxes	30,619	18,066	6,663
Depletion and accretion expense	105,752	94,661	79,947
Impairments of long-lived assets	—	—	5,725
General and administrative	14,223	10,179	10,108
Gain on disposal of oil and natural gas properties	—	(2,279)	(648)
Total operating costs and expenses	195,272	146,960	122,193
Net operating income (loss)	302,145	143,233	(35,095)
OTHER (EXPENSE) INCOME			
(Loss) gain on derivatives - commodity derivatives	(25,324)	(32,389)	13,006
Interest expense	(1,989)	(2,385)	(1,841)
Gain on derivatives - common stock warrants	362	—	—
Total other (expense) income	(26,951)	(34,774)	11,165
INCOME (LOSS) BEFORE INCOME TAXES	275,194	108,459	(23,930)
Income tax expense	12,850	—	—
NET INCOME (LOSS)	<u>\$ 262,344</u>	<u>\$ 108,459</u>	<u>\$ (23,930)</u>
NET INCOME (LOSS) PER SHARE:			
Basic	\$ 1.97	\$ 0.82	\$ (0.18)
Diluted	\$ 1.97	\$ 0.82	\$ (0.18)
WEIGHTED-AVERAGE NUMBER OF SHARES OUTSTANDING:			
Basic	132,923	132,923	132,923
Diluted	133,074	132,923	132,923

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

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2022, 2021 AND 2020

(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, 2020	\$ 324,369	—	\$ —	\$ —	\$ —	—	\$ —	\$324,369
Cash distributions	(12,883)	—	—	—	—	—	—	(12,883)
Contributed capital	83,000	—	—	—	—	—	—	83,000
Carried interest reallocation	—	—	—	—	—	—	—	—
Net loss	(23,930)	—	—	—	—	—	—	(23,930)
As of December 31, 2020	\$ 370,556	—	\$ —	\$ —	\$ —	—	\$ —	\$370,556
Cash distributions	(51,085)	—	—	—	—	—	—	(51,085)
Contributed capital	47,000	—	—	—	—	—	—	47,000
Carried interest reallocation	—	—	—	—	—	—	—	—
Net income	108,459	—	—	—	—	—	—	108,459
As of December 31, 2021	\$ 474,930	—	\$ —	\$ —	\$ —	—	\$ —	\$474,930
Net income prior to Business Combination	219,292	—	—	—	—	—	—	219,292
Contribution of Funds' assets in exchange for common stock	(694,222)	130,000	13	694,209	—	—	—	—
Recapitalization	—	2,923	—	6,825	—	—	—	6,825
Issuance costs	—	—	—	(18,508)	—	—	—	(18,508)
Issuance of common stock warrants	—	—	—	(12,265)	—	—	—	(12,265)
Issuance of vesting shares	—	372	—	(1,287)	—	—	—	(1,287)
Deferred income tax liability at Business Combination	—	—	—	(78,742)	—	—	—	(78,742)
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	\$ 590,232	\$ 32,388	(26)	\$ (229)	\$622,404

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

GRANITE RIDGE RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2022, 2021 AND 2020

(in thousands)	Year Ended December 31,		
	2022	2021	2020
Operating activities:			
Net income (loss)	\$ 262,344	\$ 108,459	\$ (23,930)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion and accretion expense	105,752	94,661	79,947
Impairments of long-lived assets	—	—	5,725
Loss (gain) on derivatives - commodity derivatives	25,324	32,389	(13,006)
Net cash (payments on) receipts from derivatives	(42,437)	(25,219)	11,913
Gain on disposal of oil and gas properties	—	(2,279)	(648)
Amortization of loan origination costs	159	48	108
Gain on derivatives - common stock warrants	(362)	—	—
Deferred income taxes	12,850	—	—
Increase (decrease) in cash attributable to changes in operating assets and liabilities:			
Revenue receivable	(24,989)	(28,603)	5,532
Accrued expenses	9,838	1,840	(194)
Prepaid and other expenses	(2,095)	(125)	1,355
Other payable	5	10	4
Net cash provided by operating activities	346,389	181,181	66,806
Investing activities:			
Additions to oil and natural gas properties	(185,497)	(136,077)	(99,487)
Acquisition of oil and natural gas properties	(49,191)	(83,209)	(17,903)
Deposit on acquisition	(1,899)	—	—
Refund of advances to operators	1,180	3,819	—
Proceeds from the disposal of oil and natural gas properties	4,845	29,443	647
Net cash used in investing activities	(230,562)	(186,024)	(116,743)
Financing activities:			
Proceeds from borrowing on credit facilities	21,000	62,000	36,500
Repayments of borrowing on credit facilities	(72,100)	(49,400)	(54,500)
Cash distributions	—	(51,091)	(12,876)
Cash contributions	—	46,980	82,947
Deferred financing costs	(3,237)	—	—
Payment of expenses related to formation of Granite Ridge Resources, Inc.	(18,456)	—	—
Purchase of treasury shares	(216)	—	—
Payment of dividends	(10,664)	—	—
Proceeds from issuance of common stock	6,825	—	—
Net cash (used in) provided by financing activities	(76,848)	8,489	52,071
Net increase in cash and restricted cash	38,979	3,646	2,134
Cash and restricted cash at beginning of year	12,154	8,508	6,374
Cash and restricted cash at end of year	\$ 51,133	\$ 12,154	\$ 8,508
Supplemental disclosure of cash flow information:			
Cash paid during the year for interest	\$ (2,286)	\$ (1,636)	\$ (1,263)
Cash (paid) received during the year for income taxes	\$ (98)	\$ (79)	\$ 65
Supplemental disclosure of non-cash investing activities:			
Oil and natural gas property development costs in accrued expenses	\$ 48,187	\$ 6,251	\$ 5,746
Advances to operators applied to development of oil and natural gas properties	\$ 103,535	\$ 48,387	\$ 38,311
Cash and restricted cash:			
Cash	\$ 50,833	\$ 11,854	\$ 8,208
Restricted cash included in other long-term assets	300	300	300
Cash and restricted cash	\$ 51,133	\$ 12,154	\$ 8,508

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

GRANITE RIDGE RESOURCES, INC.

Notes to the Consolidated Financial Statements

1. Organization and nature of operations

Granite Ridge Resources, Inc. (together with its consolidated subsidiaries, “Granite Ridge” the “Company” or the “Successor”) is a Delaware corporation, initially formed in May 2022, whose common stock and warrants are 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 (“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.

GRANITE RIDGE RESOURCES, INC.

Notes to the Consolidated Financial Statements

as a result of the Transactions. At the effective time of the Mergers, (i) 495,357 shares of ENPC Class F common stock were converted to 1,238,393 shares of ENPC Class A common stock (of which an aggregate of 220,348 shares were subsequently forfeited pursuant to the terms of the Sponsor Agreement) and the remaining shares of ENPC Class F common stock outstanding were automatically cancelled for no consideration (the "ENPC Class F Conversion") (ii) all other remaining shares of ENPC Class A common stock automatically cancelled without any conversion, payment or distribution (the "Sponsor Share Cancellation") and (iii) all shares of ENPC Class B common stock outstanding were deemed transferred to ENPC and surrendered and forfeited for no consideration (the "ENPC Class B Contribution"). 220,348 of the 371,518 shares subject to vesting and forfeiture provisions were forfeited in January 2023.

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.

2. Summary of significant accounting policies

Principles of Consolidation

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

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

Basis of Presentation

As a result of the Business Combination, periods prior to October 24, 2022 reflect Funds as limited partnerships, not as corporations. The primary financial impacts of the Transactions to the consolidated financial statements were (i) reclassification of partnership capital accounts to equity accounts reflective of a corporation and (ii) income tax effects. Since 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"). The Company operates in a one operating segment, which is oil and natural

GRANITE RIDGE RESOURCES, INC.

Notes to the Consolidated Financial Statements

gas development, exploration and production. All of our operations are conducted in the geographic area of the United States. The Company's chief operating decision maker, manages operations on a consolidated basis for purposes of evaluating operations and allocating resources.

Use of Estimates

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

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

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

Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period 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.

As of December 31, 2022 and 2021, the Company had \$0.3 million of cash classified as restricted. This balance relates to a cash deposit for two standby letters of credit associated with oil and natural gas mining lease agreements. Restricted cash consists of cash that is stated at cost, which approximates fair market value. Classification of restricted cash is based on the nature of the restrictions associated with the underlying assets.

GRANITE RIDGE RESOURCES, INC.

Notes to the Consolidated Financial Statements

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 writes off specific accounts receivable when they become uncollectible. For the years ended December 31, 2022, 2021 and 2020, the Company's bad debt expense and allowance for doubtful accounts was immaterial.

Advance to Operators

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

Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for oil and gas producing activities, as further defined under ASC 932, *Extractive Activities - Oil and Gas* ("ASC 932"). Costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory leases that find proved reserves, and to drill and equip development leases and related asset retirement costs are capitalized. Costs to drill exploratory wells are capitalized pending determinations of whether the wells have proved reserves. If the Company determines that the wells do not have proved reserves, the costs are charged to expense.

There were no exploratory wells capitalized pending determinations of whether the wells have proved reserves as of December 31, 2022 and 2021.

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 \$105.3 million, \$94.2 million and \$79.5 million for the years ended December 31, 2022, 2021, and 2020, respectively. As a result of the Business Combination, the Company aggregated certain proved properties for amortization and impairment purposes.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until the related project is completed. The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. For the years ended December 31, 2022, 2021 and 2020, no interest costs were capitalized because its exploration and development projects generally last less than six months. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

Effective January 1, 2019, the Company adopted ASU 2017-1, *Business Combinations: Clarifying the Definition of Business* ("ASU 2017-1"), with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. See discussions of the Company's oil and natural gas asset acquisitions and business combinations in Note 5.

GRANITE RIDGE RESOURCES, INC.

Notes to the Consolidated Financial Statements

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire depletion base is sold. However, gain or loss is recognized from the sale of less than an entire depletion base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. See Note 5 for additional information on our divestitures. Ordinary maintenance and repair costs are expensed as incurred.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties and integrated assets would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and risk-adjusted unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs and cash flows from integrated assets. The Company did not recognize an impairment expense for the years ended December 31, 2022 and 2021 related to its proved oil and natural gas properties. During the year ended December 31, 2020, the Company recognized an impairment expense of \$5.7 million related to its proved oil and natural gas properties.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the projects. The Company did not recognize an impairment expense for the years ended December 31, 2022, 2021 and 2020 related to its unproved oil and natural gas properties.

Derivative Instruments- Commodity Derivatives

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

Derivative Instruments- Common Stock Warrants

The Company accounts for warrants as liability-classified instruments based on an assessment of the warrant's specific terms and applicable authoritative guidance in Accounting Standards Codification ("ASC") Topic 480, "Distinguishing Liabilities from Equity" ("ASC 480") and ASC Topic 815, "Derivatives and Hedging" ("ASC 815"). The warrants are 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 are recognized as a non-operating gain or loss on the consolidated statements of operations. For the period during which the Company's common stock was publicly traded, the fair value of the warrants was based on quoted prices in an active market. Refer to Note 4 for further discussion on fair value considerations.

Asset Retirement Obligation

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

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settles the obligation for its recorded amount or incurs a gain or loss for the difference of the settled amount and recorded liability.

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

Revenue Recognition

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

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

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

The Company does not disclose the value of unsatisfied performance obligations under its contracts with customers as it applies the practical expedient in accordance with ASC 606. The expedient, as described in ASC 606-10-50-14(a), applies to variable consideration that is recognized as control of the product is transferred to the customer. Since each unit of product represents a separate performance obligation, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Non-operated Crude Oil and Natural Gas Revenues

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

Take-in Kind Oil and Natural Gas Revenues

Under certain arrangements, the Company has the right to take a volume of processed residue gas and/or NGLs in-kind at the tailgate of the midstream customer's processing plant in lieu of receiving a net payment from the operator representing its proportionate share of its natural gas production. The Company currently takes certain processed gas volumes in kind

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in lieu of monetary settlement but does not currently take NGL volumes. When the Company elects to take volumes in kind, it pays third parties to transport the processed products it took in-kind to downstream delivery points, where it then sells to customers at prices applicable to those downstream markets. In such situations, revenues are recognized during the month in which control transfers to the customer at the delivery point and it is probable the Company will collect the consideration it is entitled to receive. Sales proceeds are generally received by the Company within one month after the month in which a sale has occurred. In these scenarios, gathering and processing costs and transportation expenses the Company incurs to transport the processed products to downstream customers are recorded in Lease Operating Expenses on the Consolidated Statements of Operations.

The Company's disaggregated revenue has two primary sources: oil sales and natural gas sales. Substantially all of the Company's oil and natural gas sales come from six geographic areas in the United States: the Eagle Ford Basin (Texas), the Permian Basin (Texas), the Haynesville Basin (Texas/Louisiana), the Denver-Julesburg "DJ" Basin (Colorado), the Bakken Basin (Montana/North Dakota) and the SCOOP/STACK Basin (Oklahoma). The following tables present the disaggregation of the Company's oil revenues and natural gas revenues by basin for the years ended December 31, 2022, 2021 and 2020.

(in thousands)	Year Ended December 31,		
	2022	2021	2020
Oil	\$ 338,163	\$ 215,250	\$ 70,870
Natural gas	159,254	74,943	16,228
Total	\$ 497,417	\$ 290,193	\$ 87,098
Permian	\$ 266,856	\$ 151,179	\$ 37,205
Eagle Ford	64,879	40,898	12,554
Bakken	64,999	56,055	27,769
Haynesville	62,743	12,039	9,110
DJ	37,880	29,191	—
SCOOP/STACK	60	831	460
Total	\$ 497,417	\$ 290,193	\$ 87,098

Lease Operating Expenses

Lease operating expenses represents field employees' salaries, saltwater disposal, repairs and maintenance, expensed work overs 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, 2022, 2021 and 2020 were approximately \$26.9 million, \$17.1 million and \$6.0 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, 2022, 2021 and 2020 were approximately \$3.7 million, \$1.0 million and \$0.7 million, respectively.

Income Taxes

Prior to the Business Combination, GREP and the associated activities held by 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

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for income taxes under the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rate on deferred income tax assets and liabilities is recognized in income in the period that includes the enactment date.

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

Recently Issued and Applicable Accounting Pronouncements

The FASB issued ASU No. 2016-02, "Leases (Topic 842)" which requires all leases greater than one year to be recognized as assets and liabilities. This ASU also expands the required quantitative and qualitative disclosures surrounding leases. Oil and gas leases are excluded from the guidance. We adopted this ASU on January 1, 2022 and there was no material impacts to our consolidated financial statements.

The FASB issued ASU No. 2016-13, "Financial Instruments — Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments" which replaces the current "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. This guidance becomes effective for fiscal years beginning after December 15, 2022, however, the impact is not expected to be material.

3. Derivative financial instruments

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

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

Collar and Producer 3-way Option Contracts

The Company's derivative financial instruments consist of collar and producer 3-way option contracts.

A collar option is established with the sale of a short call option and the purchase of a long put option 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.

A producer 3-way contract is established with the sale of a short call option and the purchase of a long put option set to expire at a predetermined date in the future. However, the producer 3-way contract also includes the sale of a short put option 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.

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

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Notes to the Consolidated Financial Statements

Volume of Derivative Activities

The following table sets forth the Company's outstanding commodity derivative contracts as of December 31, 2022. All of the Company's commodity derivative contracts as of December 31, 2022 are expected to settle by December 31, 2023.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Producer 3-way (oil)					
2023					
Volume (Bbl)	431,160	340,263	228,659	208,488	1,208,570
Weighted-average sub-floor price (\$/Bbl)	\$ 57.22	\$ 62.22	\$ 60.42	\$ 60.43	\$ 59.79
Weighted-average floor price (\$/Bbl)	\$ 70.62	\$ 77.89	\$ 79.25	\$ 80.00	\$ 75.92
Weighted-average ceiling price (\$/Bbl)	\$ 96.04	\$ 99.23	\$ 100.61	\$ 101.92	\$ 98.82
Producer 3-way (natural gas)					
2023					
Volume (Mcf)	2,634,993	—	—	—	2,634,993
Weighted-average sub-floor price (\$/Mcf)	\$ 4.41	\$ —	\$ —	\$ —	\$ 4.41
Weighted-average floor price (\$/Mcf)	\$ 5.51	\$ —	\$ —	\$ —	\$ 5.51
Weighted-average ceiling price (\$/Mcf)	\$ 11.28	\$ —	\$ —	\$ —	\$ 11.28
Collar (natural gas)					
2023					
Volume (Mcf)	774,634	3,051,421	2,530,000	2,070,000	8,426,055
Weighted-average floor price (\$/Mcf)	\$ 5.96	\$ 4.12	\$ 4.25	\$ 4.50	\$ 4.42
Weighted-average ceiling price (\$/Mcf)	\$ 9.15	\$ 5.63	\$ 5.90	\$ 6.35	\$ 6.21

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, 2022, 2021 and 2020:

(in thousands)	Year Ended December 31,		
	2022	2021	2020
(Loss) gain on commodity derivatives			
Oil derivatives	\$ (14,985)	\$ (24,885)	\$ 11,604
Natural gas derivatives	(10,339)	(7,504)	1,402
Total	\$ (25,324)	\$ (32,389)	\$ 13,006

The following table represents the Company's net cash receipts (payments on) commodity derivatives for the years ended December 31, 2022, 2021 and 2020:

(in thousands)	Year Ended December 31,		
	2022	2021	2020
Net cash (payments on) receipts from commodity derivatives			
Oil derivatives	\$ (23,695)	\$ (19,034)	\$ 10,180
Natural gas derivatives	(18,742)	(6,185)	1,733
Total	\$ (42,437)	\$ (25,219)	\$ 11,913

Common stock warrants

On October 24, 2022, in connection with the Business Combination, the Company issued 10,349,975 common stock warrants. Each warrant entitles 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 will expire five-years after the completion of the Business Combination. The Company has the right to

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Notes to the Consolidated Financial Statements

redeem the common stock warrants at a price of \$0.01 per warrant when the price of Granite Ridge's common stock equals or exceeds \$ 18.00 for 20 days within a 30-day trading period.

The common stock warrants were initially recognized as a liability with a fair value of \$12.3 million and were remeasured to a fair value of \$11.9 million as of December 31, 2022. We recognized a gain of \$0.4 million during 2022 from the change in fair value of the warrant liability in the consolidated statements of operations. No common stock warrants were exercised during 2022.

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.

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The following table presents the carrying amounts and fair values of the Company's financial instruments as of December 31, 2022 and 2021:

(in thousands)	December 31, 2022		December 31, 2021	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Assets:				
Derivative instruments - commodity derivatives	\$ 10,089	\$ 10,089	\$ 465	\$ 465
Liabilities:				
Derivative instruments - common stock warrants	\$ 11,902	\$ 11,902	\$ —	\$ —
Revolving credit facilities	\$ —	\$ —	\$ 51,100	\$ 51,100
Derivative instruments - commodity derivatives	\$ 431	\$ 431	\$ 7,920	\$ 7,920

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

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

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

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

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

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Notes to the Consolidated Financial Statements

consolidated balance sheets as of December 31, 2022 and 2021. The Company nets the fair value of commodity derivative instruments by counterparty in the Company's consolidated balance sheets.

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

Year Ended December 31, 2021						
(in thousands)	Fair Value Measurement Using			Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
	Level 1	Level 2	Level 3			
Assets (at fair value):						
Commodity derivatives – current portion	\$ —	\$ 4,821	\$ —	\$ 4,821	\$ (4,387)	\$ 434
Commodity derivatives – noncurrent portion	—	2,147	—	2,147	(2,116)	31
Liabilities (at fair value):						
Commodity derivatives – current portion	—	(11,649)	—	(11,649)	4,386	(7,263)
Commodity derivatives – noncurrent portion	—	(2,774)	—	(2,774)	2,117	(657)
Net derivative instruments	<u>\$ —</u>	<u>\$ (7,455)</u>	<u>\$ —</u>	<u>\$ (7,455)</u>	<u>\$ —</u>	<u>\$ (7,455)</u>

Fair Values – Non Recurring

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

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

As of December 31, 2022, the Company's estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2023 price of \$79.12 per barrel of oil decreasing to a 2027 price of \$64.14 per barrel of oil. Natural gas prices ranged from a 2023 price of \$4.26 per Mcf of natural gas increasing to a 2027 price of \$4.50 per Mcf. Both oil and natural gas commodity prices for this purpose were held flat after 2027.

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

The Company did not recognize any impairment loss during the years ended December 31, 2022 or 2021.

During the year ended December 31, 2020, the carrying value of oil and natural gas properties were impaired to an estimated fair value. The fair value of oil and natural gas assets impaired, based on the grouping of the oil and natural gas assets by basin, was approximately \$4.9 million at December 31, 2020, resulting in impairment losses of approximately \$5.7 million for the year ended December 31, 2020. The grouping of oil and natural gas assets impaired included the SCOOP/STACK and Bakken basins, whose fair values were approximately \$1.8 million and \$3.1 million, respectively, at December 31, 2020.

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

5. Acquisitions and Divestitures

The Company follows ASU 2017-1 in evaluating whether acquisitions of oil and natural gas properties are accounted for as asset acquisitions or as business combinations. The majority of the Company's acquisitions during 2022, 2021 and 2020 qualified as asset acquisitions. Acquisitions that qualified as business combinations, as discussed below, were accounted for in accordance with ASC Topic 805, *Business Combinations*.

2022 Acquisitions

During the year ended December 31, 2022, the Company acquired various oil and natural gas properties, which included working interests ranging from 0.11% to 40%, and net revenue interests ranging from 0.09% to 29%. These included the following transactions:

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

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

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

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

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

2022 Divestitures

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

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

2021 Acquisitions

For the year ended December 31, 2021, the Company acquired various oil and natural gas properties, which included working interests ranging from 0.01%-34.79% and net revenue interests ranging from 0.01%-25.61%.

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

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

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

2021 Divestitures

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

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

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

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

GRANITE RIDGE RESOURCES, INC.**Notes to the Consolidated Financial Statements****2020 Acquisitions**

For the year ended December 31, 2020, the Company acquired various proved oil and natural gas properties, which included working interests ranging from 0.37%-50.00% and net revenue interests ranging from 0.01%-37.50%. These included the following transactions:

Bakken Basin – During the year ended December 31, 2020, the Company acquired various proved oil and natural gas properties in the Bakken Basin for \$0.7 million, consisting of proved developed nonproducing oil and natural gas properties and proved undeveloped oil and natural gas properties.

Permian Basin - During the year ended December 31, 2020, the Company acquired various proved oil and natural gas properties in the Permian Basin for \$11.6 million, consisting of proved undeveloped oil and natural gas properties and proved developed nonproducing oil and natural gas properties.

In addition, the Company acquired proved oil and natural gas properties in the Permian Basin for \$1.8 million that included proved developed producing properties. This acquisition met the definition of a business combination. The fair value of assets acquired and liabilities assumed is outlined in the table below.

Eagle Ford - During the year ended December 31, 2020, the Company acquired proved oil and natural gas properties in the Eagle Ford Basin for \$3.0 million that included proved developed producing properties. This acquisition met the definition of a business combination. The fair value of assets acquired and liabilities assumed is outlined in the table below.

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:

<i>(in thousands)</i>	December 31, 2020
Fair value of proved assets acquired and liabilities assumed	
Proved oil and gas properties (1)	\$ 4,943
Less: Asset retirement obligations	(130)
Net asset acquired	4,813
Consideration transferred (including liabilities assumed)	\$ 4,813

(1) Amount includes asset retirement costs of \$0.1 million for 2020.

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.

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The following table presents the changes in the asset retirement obligations during the years ended December 31, 2022, 2021 and 2020:

(in thousands)	Year Ended December 31,		
	2022	2021	2020
Asset retirement obligations, beginning of year	\$ 2,962	\$ 3,114	\$ 1,561
Liabilities incurred during the period	1,012	465	329
Revision of estimates (1)	490	(868)	814
Accretion of discount during the period	499	447	410
Disposals or settlements	—	(196)	—
Asset retirement obligations, end of year	\$ 4,963	\$ 2,962	\$ 3,114

(1) Revisions in estimated liabilities 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. Prior to the Business Combination, GREP and the associated activities held by Funds were treated as partnerships for U.S. federal income tax purposes and were not subject to U.S. federal income tax. Any taxable income or loss generated prior to the Business Combination was passed through to and included in the taxable income or loss of its members. As a result of the Business Combination, the Funds' net assets were transferred to the Company resulting in carryover tax basis of those assets. The Company is a C corporation and subject to U.S. federal income tax and state and local income taxes.

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

(in thousands)	Year Ended December 31,		
	2022	2021	2020
Current			
Federal	\$ —	\$ —	\$ —
State	—	—	—
Deferred			
Federal	\$ 11,444	\$ —	\$ —
State	1,406	—	—
	12,850	—	—
Income tax expense	\$ 12,850	\$ —	\$ —

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The Company's effective tax rate was 4.7%, 0% and 0% for years ended December 31, 2022, 2021 and 2020, respectively. The effective tax rate differs from the enacted statutory rate of 21% primarily due to the allocations of profits and losses to ultimate members prior to the Business Combination and the impact of state income taxes.

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

(in thousands)	Year Ended December 31,		
	2022	2021	2020
Income (loss) before income taxes	\$ 275,194	\$ 108,459	\$ (23,930)
Income tax expense (benefit) at federal statutory rate	57,791	22,776	(5,025)
Net (income) loss prior to Business Combination - non taxable	(46,051)	(22,776)	5,025
State income taxes, net of federal benefit	1,110	—	—
Income tax expense	\$ 12,850	\$ —	\$ —
Effective tax rate	4.7%	0.0%	0.0%

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

(in thousands)	Year Ended December 31,	
	2022	2021
Deferred tax assets		
Net operating loss carryforwards	\$ 11,500	\$ —
Asset retirement obligation	1,128	—
Other deductible temporary differences	88	—
Total deferred tax assets	12,716	—
Less: valuation allowance	—	—
Net deferred tax assets	\$ 12,716	\$ —
Deferred tax liabilities		
Property, plant and equipment	\$ (102,112)	\$ —
Unrealized derivatives	(2,196)	—
Total deferred tax liabilities	(104,308)	—
Net deferred tax liability	\$ (91,592)	\$ —

As of December 31, 2022, the Company had accumulated federal net operating loss carryforward of \$51.6 million, none of which are expected to expire, and state net operating loss carryforwards of approximately \$51.6 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 Internal Revenue Code. As of December 31, 2022, 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, 2022, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes for tax years 2019 through 2022 and state income taxes for tax years 2018 through 2022.

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, 2022 and 2021, the Company had no unrecognized tax benefits and did not recognize any interest or penalties during those respective periods related to unrecognized tax benefits.

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

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 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 Treasury is expected to publish regulations relevant to many aspects of the IRA. The Company is currently awaiting such guidance and continues to evaluate the effect of the new law to its future cash flows and financial results. The Company is currently evaluating the impact of the IRA on its cash taxes and income tax expense for the 2023 tax year.

8. Debt

The carrying value of total debt is summarized at December 31, 2022 and 2021 as follows:

(in thousands)	December 31,	
	2022	2021
Fund I Facility	\$ —	\$ 1,100
Fund II Facility	—	20,000
Fund III Facility	—	30,000
Granite Ridge Credit Agreement	—	—
Total debt	—	51,100
Less: Current portion of outstanding debt	—	(50,000)
Total long-term debt	\$ —	\$ 1,100

The Funds' Credit Facilities

The Funds maintained three revolving credit facilities prior to the Business Combination, with an aggregate outstanding balance of \$51.1 million as of December 31, 2021. The Funds repaid all amounts outstanding under these credit facilities and terminated these credit facilities on October 24, 2022 in connection with the closing of the Business Combination and Granite Ridge's entry into a new credit facility.

Granite Ridge Credit Agreement

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

The Credit Agreement provides for aggregate elected commitments of \$150.0 million, an initial borrowing base of \$325.0 million and an aggregate maximum revolving credit amount of \$1.0 billion. The borrowing base is scheduled to be redetermined semiannually on or about April 1 and October 1 of each calendar year, commencing April 1, 2023, 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. Additionally, the borrower and each of the Required Lenders (as defined in the Credit Agreement) may request one unscheduled redetermination of the borrowing base between each scheduled redetermination. The amount of the borrowing base is determined by the lenders in their sole discretion and consistent with the oil and gas lending criteria of the lenders at the time of the relevant redetermination. The amount Granite Ridge is able to borrow under the Credit Agreement is subject to compliance with the financial covenants, satisfaction of various conditions precedent to borrowing and other provisions of the Credit Agreement. Granite Ridge does not have any borrowings or letters of credit outstanding under the Credit Agreement at December 31, 2022, resulting in availability of \$150.0 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 assets of the Company and its restricted subsidiaries.

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Notes to the Consolidated Financial Statements

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 250 to 350 basis points, depending on the percentage of the borrowing base utilized, plus an additional 10, 15 or 20 basis point credit spread adjustment for a one, three or six month interest period, respectively. Base rate loans 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 an applicable margin ranging from 150 to 250 basis points, depending on the percentage of the borrowing base utilized. We also pay a commitment fee on unused elected commitment amounts under its facility of 50 basis points. We may repay any amounts borrowed under the Credit Agreement prior to the maturity date without any premium or penalty.

The Credit Agreement 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), subject to certain adjustments, of not greater than 3.00 to 1.00 as of the last day of any fiscal quarter (commencing with the fiscal quarter ending December 31, 2022), and
- (ii) a current ratio (as defined in the Credit Agreement), subject to certain adjustments, of not less than 1.00 to 1.00 as of the last day of any fiscal quarter (commencing with the fiscal quarter ending December 31, 2022).

At December 31, 2022, the Company, was in compliance with all covenants required by the Credit Agreement.

9. Equity

As a result of the Business Combination, periods prior to December 31, 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.

At December 31, 2022, the Company had 431,000,000 authorized shares of capital stock, each with a par value of \$0.0001 per share, and had issued 133,294,897 shares of common stock.

In connection with the closing of the Transaction, the Company's Board of Directors adopted the Granite Ridge 2022 Omnibus Incentive Plan ("the Plan"), which provides for granting, among others, stock options, restricted stock awards and other awards 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 will not exceed 6,500,000 shares. No shares were issued under the Plan as of December 31, 2022.

Common stock dividends - The Company paid dividends of \$10.7 million, or \$0.08 per share during the fourth quarter of 2022. 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 of the Company's common stock through December 31, 2023. Under the stock repurchase program, the Company will repurchase shares of its common stock from time to time in open market transactions or in privately negotiated transactions as permitted under applicable rules and regulations. The Board of

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Directors of the Company may limit or terminate the stock repurchase program at any time without prior notice, but, with no further action of the Board of Directors of the Company, the stock repurchase program will terminate on December 31, 2023.

At December 31, 2022, the Company had repurchased 25,920 shares under the program at an aggregate cost of \$0.2 million. The extent to which the Company repurchases its shares of common stock, and the timing of such repurchases, will depend upon market conditions and other considerations as may be considered in the Company's sole discretion.

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. On the date of the Business Combination, the Company recorded a liability related to the Vesting Shares of \$1.3 million. In January 2023, 151,170 of these shares vested and the remaining shares were forfeited.

10. Related party transactions

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

Prior to the Transaction, the Company paid an annual management fee to an entity under common control as compensation for providing managerial services to the Company.

For the periods ended December 31, 2022, December 31, 2021 and December 31, 2020, total management fees for the Company were approximately \$7.9 million, \$6.2 million and \$6.6 million, respectively, and are included in general and administrative expenses within the accompanying consolidated statements of operations.

11. Commitments and contingencies

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

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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, 2022, 2021 and 2020.

Major Operators	2022	2021	2020
Operator A	*	*	11 %
Operator B	*	*	13 %
Operator C	12 %	12 %	17 %
Operator D	*	15 %	*
Operator E	10 %	*	*
Operator F	10 %	*	*

*Less than 10%

No other operator accounted for 10% or more of revenue attributable to the Company's assets on a combined basis in the years ended December 31, 2022, 2021, or 2020. The loss of any such operator could adversely affect revenues attributable to the Company's assets in the short term.

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

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

GRANITE RIDGE RESOURCES, INC.**Notes to the Consolidated Financial Statements****13. Earnings Per Share**

The Company's basic earnings (loss) per share are computed by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares outstanding for the period. Diluted EPS is computed by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares and potential common shares outstanding (if dilutive) during each period.

The following table presents the basic and diluted earnings per share computations for the years ended December 31, 2022, 2021 and 2020:

(in thousands)	December 31,		
	2022	2021	2020
Net income (loss)	\$ 262,344	\$ 108,459	\$ (23,930)
Weighted average common shares outstanding:			
Weighted average common shares outstanding – basic	132,923	132,923	132,923
Weighted average common shares outstanding – diluted	133,074	132,923	132,923
Net income (loss) per common share:			
Basic	\$ 1.97	\$ 0.82	\$ (0.18)
Diluted	\$ 1.97	\$ 0.82	\$ (0.18)

Diluted weighted average common shares outstanding include certain Vesting Shares, as defined in Note 9, that are expected to vest in January 2023. There were no dilutive securities outstanding for the years ended December 31, 2021 and 2020.

Diluted net earnings per share for the year ended December 31, 2022 excluded 10,349,975 common stock warrants outstanding as inclusion of these items would be antidilutive.

14. Subsequent Events

On February 21, 2023, our Board of Directors declared a cash dividend of \$0.11 per share for the first quarter of 2023. Dividend payment of \$14.6 million was paid on March 15, 2023 to stockholders of record as of March 1, 2023.

During the first quarter of 2023, the Company acquired oil and natural gas properties in the DJ Basin and Permian Basin for \$17.9 million and \$6.9 million, respectively.

From January 1, 2023 to March 22, 2023, the Company repurchased 222,498 shares under the share repurchase program at an aggregate cost of \$1.4 million.

GRANITE RIDGE RESOURCES, INC.
Notes to the Consolidated Financial Statements
Unaudited Supplementary Data
Capitalized Costs

<i>(in thousands)</i>	December 31,	
	2022	2021
Oil and natural gas properties:		
Proved	\$ 996,573	\$ 702,141
Unproved	32,089	25,406
Less: accumulated depletion	(383,673)	(278,773)
Net capitalized costs for oil and natural gas properties	\$ 644,989	\$ 448,774

Costs Incurred for Oil and Natural Gas Producing Activities

<i>(in thousands)</i>	December 31,		
	2022	2021	2020
Property acquisition costs:			
Proved	\$ 26,218	\$ 42,569	\$ 18,059
Unproved	22,973	40,598	—
Development costs	256,664	103,918	99,188
Total costs incurred for oil and natural gas properties	\$ 305,855	\$ 187,085	\$ 117,247

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,		
	2022	2021	2020
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	\$ 94.14	\$ 66.55	\$ 39.54
Natural gas per Mcf	6.36	3.60	1.99

The following tables present the Company's third-party independent reserve engineers estimates of its proved developed and undeveloped oil and natural gas reserves. The Company emphasized that reserves are approximations and are expected to change as additional information becomes available. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas that cannot be measured in an exact way, and the accuracy of any

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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, 2019	16,507	116,748	35,967
Revisions of previous estimates	(3,567)	(42,947)	(10,726)
Extensions and discoveries	1,429	2,834	1,900
Divestiture of reserves	(65)	(95)	(81)
Acquisition of reserves	4,053	8,677	5,499
Production	(1,895)	(10,294)	(3,611)
Proved developed and undeveloped reserves at December 31, 2020	16,462	74,923	28,948
Revisions of previous estimates	651	18,964	3,814
Extensions and discoveries	2,543	9,420	4,113
Divestiture of reserves	(1,098)	(2,353)	(1,491)
Acquisition of reserves	7,673	39,254	14,216
Production	(3,413)	(14,861)	(5,890)
Proved developed and undeveloped reserves at December 31, 2021	22,818	125,347	43,710
Revisions of previous estimates	(456)	6,225	581
Extensions and discoveries	3,690	27,126	8,211
Divestiture of reserves	—	—	—
Acquisition of reserves	3,098	12,892	5,247
Production	(3,656)	(21,351)	(7,215)
Proved developed and undeveloped reserves at December 31, 2022	25,494	150,239	50,534
	Oil (MBbl)	Natural Gas (MMcf)	MBoe
Proved developed reserves:			
December 31, 2019	9,504	40,702	16,288
December 31, 2020	10,053	36,585	16,150
December 31, 2021	11,658	54,257	20,702
December 31, 2022	15,714	91,034	30,886
Proved undeveloped reserves:			
December 31, 2019	7,003	76,046	19,679
December 31, 2020	6,409	38,338	12,798
December 31, 2021	11,160	71,090	23,008
December 31, 2022	9,780	59,205	19,648

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.

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Notes to the Consolidated Financial Statements

- *Extensions and discoveries.* In 2022, total extensions and discoveries of 8,211 MBoe were primarily attributable to successful drilling in the Permian and Eagle Ford Basins. Proved developed reserves increased approximately 699 MBoe due to the Company's drilling activity in 2022, and 7,512 MBoe as a result of new proved undeveloped locations added.
- *Acquisitions of reserves.* In 2022, total acquisitions of reserves of 5,247 MBoe were primarily attributable to the acquisitions of oil and natural gas properties in the Permian Basin (see Note 5).

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

- *Revisions of previous estimates.* In 2021, revisions of previous estimates increased proved developed and undeveloped reserves by a net amount of 3,814 MBoe. The upward revision in reserves was due to a combination of higher crude oil prices and favorable adjustments attributable to well performance, increasing reserves by 2,636 MBoe and 1,178 MBoe, respectively.
- *Extensions and discoveries.* In 2021, total extensions and discoveries of 4,113 MBoe were primarily attributable to successful drilling in the Bakken, Eagle Ford and Permian Basins as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 354 MBoe as a result of successful drilling in the Bakken, Eagle Ford and Permian Basins and 3,759 MBoe as a result of additional proved undeveloped locations.
- *Divestiture of reserves.* In 2021, divestiture of reserves of 1,491 MBoe were primarily attributable to the sale of oil and natural gas properties in the Permian Basin (see Note 5).
- *Acquisition of reserves.* In 2021, acquisition of reserves of 14,216 MBoe were primarily attributable to acquisitions of oil and natural gas properties in the Permian, Bakken and DJ Basins (see Note 5).

Notable changes in proved reserves for the year ended December 31, 2020 included the following:

- *Revisions of previous estimates.* In 2020, revisions of previous estimates decreased proved developed and undeveloped reserves by a net amount of 10,726 MBoe. The downward revision in reserves was due to a combination of unfavorable adjustments attributable to well performance and lower crude oil prices, reducing reserves by 6,908 MBoe and 3,818 MBoe, respectively.
- *Extensions and discoveries.* In 2020, total extensions and discoveries of 1,900 MBoe were primarily attributable to successful drilling in the Permian Basin as well as the addition of proved undeveloped locations. Included in these extensions and discoveries were 637 MBoe as a result of successful drilling in the Permian Basin and 1,263 MBoe as a result of additional proved undeveloped locations.
- *Divestiture of reserves.* In 2020, divestiture of reserves of 81 MBoe were primarily attributable to the sale of oil and natural gas properties in the Bakken Basin.
- *Acquisition of reserves.* In 2020, divestiture of reserves of 5,499 MBoe were primarily attributable acquisitions of oil and natural gas properties in the Eagle Ford, Permian and Bakken Basins (see Note 5).

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

GRANITE RIDGE RESOURCES, INC.

Notes to the Consolidated Financial Statements

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 December 31, 2022, 2021 and 2020:

<i>(in thousands)</i>	December 31,		
	2022	2021	2020
Future cash inflows	\$ 3,572,271	\$ 2,007,425	\$ 713,424
Future production costs	(755,059)	(566,113)	(271,652)
Future development costs	(249,659)	(223,037)	(115,551)
Future income tax expense	(533,328)	(6,223)	(2,633)
Future net cash flows	2,034,225	1,212,052	323,588
10% discount for estimated timing of cash flows	(798,299)	(437,701)	(128,005)
Standardized measure of discounted future net cash flows	<u>\$ 1,235,926</u>	<u>\$ 774,351</u>	<u>\$ 195,583</u>

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

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

<i>(in thousands)</i>	December 31,		
	2022	2021	2020
Balance, beginning of period	\$ 774,351	\$ 195,583	\$ 310,294
Sales of oil and natural gas produced, net of production costs	(422,120)	(245,794)	(60,037)
Extensions and discoveries	239,173	58,023	14,575
Previously estimated development cost incurred during the period	93,895	22,042	30,668
Net change of prices and production costs	671,556	332,625	(124,290)
Change in future development costs	(6,186)	(3,833)	15,054
Revisions of quantity and timing estimates	44,022	50,158	(69,623)
Accretion of discount	77,823	19,714	31,190
Change in income taxes	(319,318)	(2,315)	40
Acquisition of Reserves	154,300	332,947	62,948
Divestiture of Reserves	—	(13,589)	(1,094)
Other	(71,570)	28,790	(14,142)
Balance, end of period	<u>\$ 1,235,926</u>	<u>\$ 774,351</u>	<u>\$ 195,583</u>

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

The following summary of the material terms of the securities of Granite Ridge Resources, Inc. ("Granite Ridge" or the "Company") is not intended to be a complete summary of the rights and preferences of such securities and is subject to and qualified by reference to the Company's Amended and Restated Certificate of Incorporation of Granite Ridge Resources, Inc., dated October 24, 2022 (the "Certificate of Incorporation"), and the Amended and Restated Bylaws of Granite Ridge Resources, Inc. (the "Bylaws" and together with the Certificate of Incorporation, the "Charter Documents"), each of which is included as an exhibit to the Company's most recent Annual Report on Form 10-K filed with the Securities and Exchange Commission and incorporated by reference herein. For additional information, please read the Charter Documents and the applicable provisions of the Delaware General Corporation Law (the "DGCL").

Authorized and Outstanding Capital Stock

The Certificate of Incorporation of Granite Ridge authorizes the issuance of 431,000,000 shares of common stock, par value \$0.0001 per share ("Granite Ridge common stock") and 1,000,000 shares of preferred stock, par value \$0.0001 per share ("preferred stock"). The outstanding shares of Granite Ridge common stock are duly authorized, validly issued, fully paid and non-assessable. Holders of record of Granite Ridge common stock are entitled to one vote for each share of Granite Ridge common stock held on all matters to be voted on by stockholders.

Common Stock

Voting Power

Unless otherwise required by law or as otherwise provided in any certificate of designation for any series of preferred stock, holders of record of Granite Ridge common stock are entitled to one vote for each share of Granite Ridge common stock held on all matters to be voted on by stockholders. Granite Ridge's board of directors is divided into three classes, each of which generally serves for a term of three years with only one class of directors being elected in each year and with directors only permitted to be removed for cause. There is no cumulative voting with respect to the election of directors, with the result that the holders of more than 50% of the shares voted for the election of directors can elect all of the directors up for election at such time.

Dividends

Holders of Granite Ridge common stock will be entitled to receive such dividends and other distributions, if any, as may be declared from time to time by Granite Ridge's board of directors in its discretion out of funds legally available therefor and shall share equally on a per share basis in such dividends and distributions. The payment of cash dividends in the future will be dependent upon a number of factors, including Granite Ridge's results of operations, financial condition, future prospects, contractual restrictions, restrictions imposed by applicable law, and other factors the board of directors of Granite Ridge deems relevant. The payment of any cash dividends will be within the discretion of Granite Ridge's board of directors at such time. If Granite Ridge incurs any indebtedness, Granite Ridge's ability to declare dividends may be limited by restrictive covenants Granite Ridge may agree to in connection therewith. The operating and financial restrictions and covenants in Granite Ridge's senior secured revolving credit agreement, dated October 24, 2022, restrict, and any other future financing agreements by Granite Ridge likely will restrict, its ability to pay dividends, finance future operations or capital needs, or engage, expand, or pursue its business activities.

Liquidation, Dissolution and Winding Up

In the event of the voluntary or involuntary liquidation, dissolution, distribution of assets, or winding-up of Granite Ridge, the holders of Granite Ridge common stock will be entitled to receive an equal amount per share of all of Granite Ridge's assets of whatever kind available for distribution to stockholders, after the rights of the holders of Granite Ridge's creditors and holders of preferred stock, if any, have been satisfied.

No Preemptive, Redemption or Convertible Rights

The holders of Granite Ridge common stock shall have no preemptive rights to subscribe to any or all additional issues of Granite Ridge common stock or any securities of the Company convertible into Granite Ridge common stock. Granite Ridge common stock is not redeemable nor convertible.

Preferred Stock

The Certificate of Incorporation of Granite Ridge provides that shares of preferred stock may be issued from time to time in one or more series. Granite Ridge's board of directors is authorized to fix the voting rights, if any, designations, powers,

preferences, the relative, participating, optional, or other special rights and any qualifications, limitations, and restrictions thereof, applicable to such additional shares of each series. Granite Ridge's board of directors may, without stockholder approval, issue preferred stock with voting and other rights that could adversely affect the voting power and other rights of the holders of Granite Ridge common stock and could have anti-takeover effects. The ability of Granite Ridge's board of directors to issue preferred stock without stockholder approval could have the effect of delaying, deferring, or preventing a change of control of Granite Ridge or the removal of existing management.

Warrants

As of March 22, 2023, Granite Ridge has 10,349,975 outstanding warrants to purchase Granite Ridge common stock at an exercise price of \$11.50 per share (the "warrants" and each, a "warrant").

On October 24, 2022 (the "Closing Date"), Granite Ridge and Executive Network Partnering Corporation, a Delaware corporation ("ENPC") consummated a business combination (the "Business Combination") pursuant to the terms of the Business Combination Agreement, dated May 16, 2022, by and among ENPC, Granite Ridge, and the other parties named therein. The warrants were issued at the closing of the Business Combination to the holders of ENPC's then outstanding warrants.

On the Closing Date of the Business Combination, the Company entered into the Assignment, Assumption and Amendment Agreement (the "Warrant Agreement Amendment and Assignment"), by and among the Company, ENPC and Continental Stock Transfer & Trust Company ("Continental"). The Warrant Agreement Amendment and Assignment assigned the existing Warrant Agreement, dated September 15, 2020, as amended on March 24, 2021, by and between ENPC and Continental (as amended, the "Existing Warrant Agreement") to the Company, and the Company agreed to perform all applicable obligations under such agreement.

In connection with the Business Combination, ENPC assigned all its rights, title and interest in the Existing Warrant Agreement to Granite Ridge, and the shares for which the warrants of ENPC were exercisable automatically converted to shares of Granite Ridge common stock (the ENPC Warrant Agreement as assigned to Granite Ridge following the Business Combination is referred to herein as the "Granite Ridge Warrant Agreement"). Pursuant to the Granite Ridge Warrant Agreement, each whole warrant entitles the registered holder to purchase one share of Granite Ridge common stock at a price of \$11.50 per share, subject to adjustment as discussed below, at any time commencing November 23, 2022. Pursuant to the Granite Ridge Warrant Agreement, a warrant holder may exercise its warrants only for a whole number of shares of Granite Ridge common stock. The warrants will expire five years after the Closing Date, at 5:00 p.m., New York City time, or earlier upon redemption or liquidation.

Granite Ridge will have no obligation to settle such warrant exercise unless a registration statement under the Securities Act with respect to the shares of Granite Ridge common stock underlying the warrants is then effective and a prospectus relating thereto is current, subject to Granite Ridge satisfying its obligations described below with respect to registration. No warrant will be exercisable, and Granite Ridge will not be obligated to issue a share of Granite Ridge common stock upon exercise of a warrant, unless the share of Granite Ridge common stock issuable upon such warrant exercise has been registered, qualified, or deemed to be exempt under the securities laws of the state of residence of the registered holder of the warrants. In the event that the conditions in the two immediately preceding sentences are not satisfied with respect to a warrant, the holder of such warrant will not be entitled to exercise such warrant, and such warrant may have no value and expire worthless. In no event will Granite Ridge be required to net cash settle any warrant.

Granite Ridge has filed with the Securities and Exchange Commission (the "SEC") a registration statement for the registration, under the Securities Act, of the warrants and the Granite Ridge common stock issuable upon exercise of the warrants, and Granite Ridge will use commercially reasonable efforts to maintain the effectiveness of such registration statements and a current prospectus relating to those Granite Ridge common stock until the warrants expire or are redeemed, as specified in the Granite Ridge Warrant Agreement.

From and after the sixty-first (61st) business day after the Closing Date, warrant holders may, during any period when Granite Ridge has failed to maintain an effective registration statement and until a registration statement has been declared effective by the SEC, exercise warrants on a "cashless basis" in accordance with Section 3(a)(9) of the Securities Act or another exemption. Notwithstanding the above, if shares of Granite Ridge common stock are at the time of any exercise of a warrant not listed on a national securities exchange such that they satisfy the definition of a "covered security" under Section 18(b)(1) of the Securities Act, Granite Ridge may, at its option, require holders of public warrants who exercise their warrants to do so on a "cashless basis" in accordance with Section 3(a)(9) of the Securities Act and, in the event Granite Ridge so elects, Granite Ridge will not be required to file or maintain in effect a registration statement, and in the event Granite Ridge does not so elect, Granite Ridge will use its best efforts to register or qualify the shares under applicable blue sky laws to the extent an exemption is not available.

Redemption of Warrants for Cash

Granite Ridge may call the warrants for redemption for cash:

- in whole and not in part;

- at a price of \$0.01 per warrant;
- upon not less than 30 days' prior written notice of redemption (the "30-day redemption period") to each warrant holder; and
- if, and only if, the closing price of Granite Ridge common stock equals or exceeds \$18.00 per share (as adjusted for stock splits, stock capitalizations, reorganizations, recapitalizations and the like) for any 20 trading days within a 30-trading day period ending three business days before Granite Ridge sends the notice of redemption to the warrant holders.

Granite Ridge has established the last of the redemption criterion discussed above to prevent a redemption call unless there is at the time of the call a significant premium to the warrant exercise price. If the foregoing conditions are satisfied and Granite Ridge issues a notice of redemption of the warrants, each warrant holder will be entitled to exercise his, her, or its warrant prior to the scheduled redemption date. However, the price of the shares of Granite Ridge common stock may fall below the \$18.00 redemption trigger price (as adjusted for stock splits, stock capitalizations, reorganizations, recapitalizations, and the like) as well as the \$11.50 warrant exercise price after the redemption notice is issued.

Redemption Procedures and Cashless Exercise

If Granite Ridge calls the warrants for redemption as described above, Granite Ridge will have the option to require any holder that wishes to exercise his, her, or its warrant to do so on a "cashless basis." In determining whether to require all holders to exercise their warrants on a "cashless basis," Granite Ridge will consider, among other factors, its cash position, the number of warrants that are outstanding, and the dilutive effect on Granite Ridge's stockholders of issuing the maximum number of shares of Granite Ridge common stock issuable upon the exercise of Granite Ridge's warrants. If management takes advantage of this option, all holders of warrants will pay the exercise price by surrendering their warrants for that number of shares of Granite Ridge common stock equal to the quotient obtained by dividing (x) the product of the number of shares of Granite Ridge common stock underlying the warrants, multiplied by the excess of the "fair market value" of shares of Granite Ridge common stock (defined below) over the exercise price of the warrants by (y) the fair market value. The "fair market value" will mean the average closing price of the shares of Granite Ridge common stock for the 10 trading days ending on the third trading day prior to the date on which the notice of redemption is sent to the holders of warrants. If Granite Ridge takes advantage of this option, the notice of redemption will contain the information necessary to calculate the number of shares of Granite Ridge common stock to be received upon exercise of the warrants, including the "fair market value" in such case. Requiring a cashless exercise in this manner will reduce the number of shares to be issued and thereby lessen the dilutive effect of a warrant redemption. This feature is an attractive option to Granite Ridge if Granite Ridge does not need the cash from the exercise of the warrants after the Business Combination.

A holder of a warrant may notify Granite Ridge in writing in the event it elects to be subject to a requirement that such holder will not have the right to exercise such warrant, to the extent that after giving effect to such exercise, such person (together with such person's affiliates), to the warrant agent's actual knowledge, would beneficially own in excess of 4.9% or 9.8% (as specified by the holder) of the shares of Granite Ridge common stock outstanding immediately after giving effect to such exercise.

Adjustment to Exercise Price

If the number of outstanding shares of Granite Ridge common stock is increased by a share capitalization payable in shares of Granite Ridge common stock, or by a split-up of common stock or other similar event, then, on the effective date of such share capitalization, split-up or similar event, the number of shares of Granite Ridge common stock issuable on exercise of each warrant will be increased in proportion to such increase in the outstanding shares of common stock. A rights offering to all or substantially all holders of Granite Ridge common stock entitling holders to purchase shares of Granite Ridge common stock at a price less than the fair market value will be deemed a share capitalization of a number of shares of Granite Ridge common stock equal to the product of (i) the number of shares of Granite Ridge common stock actually sold in such rights offering (or issuable under any other equity securities sold in such rights offering that are convertible into or exercisable for shares of Granite Ridge common stock) and (ii) the quotient of (x) the price per share of Granite Ridge common stock paid in such rights offering and (y) the fair market value. For these purposes (i) if the rights offering is for securities convertible into or exercisable for shares of Granite Ridge common stock, in determining the price payable for shares of Granite Ridge common stock, there will be taken into account any consideration received for such rights, as well as any additional amount payable upon exercise or conversion and (ii) fair market value means the volume weighted average price of shares of Granite Ridge common stock as reported during the ten (10) trading day period ending on the trading day prior to the first date on which the shares of Granite Ridge common stock trades on the applicable exchange or in the applicable market, regular way, without the right to receive such rights.

If the number of outstanding shares of Granite Ridge common stock is decreased by a consolidation, combination, reverse share split, or reclassification of shares of Granite Ridge common stock or other similar event, then, on the effective date of such consolidation, combination, reverse share split, reclassification, or similar event, the number of shares of Granite Ridge common stock issuable on exercise of each warrant will be decreased in proportion to such decrease in outstanding share of Granite Ridge common stock.

Whenever the number of shares of Granite Ridge common stock purchasable upon the exercise of the warrants is adjusted, as described above, the warrant exercise price will be adjusted by multiplying the warrant exercise price immediately prior to

such adjustment by a fraction (x) the numerator of which will be the number of shares of Granite Ridge common stock purchasable upon the exercise of the warrants immediately prior to such adjustment, and (y) the denominator of which will be the number of shares of Granite Ridge common stock so purchasable immediately thereafter.

In case of any reclassification or reorganization of the outstanding shares of Granite Ridge common stock (other than those described above or that solely affects the par value of such shares of Granite Ridge common stock), or in the case of any merger or consolidation of Granite Ridge with or into another corporation (other than a consolidation or merger in which Granite Ridge is the continuing corporation and that does not result in any reclassification or reorganization of outstanding shares of Granite Ridge common stock), or in the case of any sale or conveyance to another corporation or entity of the assets or other property of Granite Ridge as an entirety or substantially as an entirety in connection with which Granite Ridge is dissolved, the holders of the warrants will thereafter have the right to purchase and receive, upon the basis and upon the terms and conditions specified in the warrants and in lieu of the shares of Granite Ridge common stock immediately theretofore purchasable and receivable upon the exercise of the rights represented thereby, the kind and amount of shares of Granite Ridge common stock or other securities or property (including cash) receivable upon such reclassification, reorganization, merger or consolidation, or upon a dissolution following any such sale or transfer, that the holder of the warrants would have received if such holder had exercised their warrants immediately prior to such event. If less than 70% of the consideration receivable by the holders of shares of Granite Ridge common stock in such a transaction is payable in the form of shares of Granite Ridge common stock in the successor entity that is listed for trading on a national securities exchange or is quoted in an established over-the-counter market, or is to be so listed for trading or quoted immediately following such event, and if the registered holder of the warrant properly exercises the warrant within thirty days following public disclosure of such transaction, the warrant exercise price will be reduced as specified in the warrant agreement based on the Black-Scholes Warrant Value (as defined in the warrant agreement) of the warrant. The purpose of such exercise price reduction is to provide additional value to holders of the warrants when an extraordinary transaction occurs during the exercise period of the warrants pursuant to which the holders of the warrants otherwise do not receive the full potential value of the warrants.

The foregoing description of potential adjustments is not complete. For a full description of any potential adjustments to the warrants, warrant holders should refer to the Granite Ridge Warrant Agreement.

Other provisions

The warrants were issued in registered form under the Granite Ridge Warrant Agreement. The Granite Ridge Warrant Agreement provides that the terms of the warrants may be amended without the consent of any holder for the purpose of (i) curing any ambiguity or to correct any defective provision or mistake, including to conform the provisions of the warrant agreement to the description of the terms of the warrants and the warrant agreement, (ii) adjusting the provisions relating to cash dividends on shares of common stock as contemplated by and in accordance with the Granite Ridge Warrant Agreement or (iii) adding or changing any provisions with respect to matters or questions arising under the Granite Ridge Warrant Agreement as the parties to the Granite Ridge Warrant Agreement may deem necessary or desirable and that the parties deem to not adversely affect the rights of the registered holders of the warrants, provided that the approval by the holders of at least 50% of the then outstanding public warrants that vote to amend the Granite Ridge Warrant Agreement, after at least 10 days' notice that an amendment is being sought, is required to make any change that adversely affects the interests of the registered holders of public warrants.

The warrants may be exercised upon surrender of the warrant certificate on or prior to the expiration date at the offices of the warrant agent, with the exercise form on the reverse side of the warrant certificate completed and executed as indicated, accompanied by full payment of the exercise price (or on a cashless basis, if applicable), by certified or official bank check payable to Granite Ridge, for the number of warrants being exercised. The warrant holders do not have the rights or privileges of holders of Granite Ridge common stock and any voting rights until they exercise their warrants and receive shares of Granite Ridge common stock. After the issuance of shares of Granite Ridge common stock upon exercise of the warrants, each holder will be entitled to one vote for each share held of record on all matters to be voted on by stockholders.

No fractional shares will be issued upon exercise of the warrants. If, upon exercise of the warrants, a holder would be entitled to receive a fractional interest in a share, Granite Ridge will, upon exercise, round down to the nearest whole number the number of shares of Granite Ridge common stock to be issued to the warrant holder.

Voting limitation

The Granite Ridge Warrant Agreement provides that no holder may vote more than 15% of the outstanding public warrants (measured on a beneficial basis and including such holder's affiliates) unless consented to by Granite Ridge in writing to the warrant agent. In order to vote a public warrant, the beneficial owner thereof must identify itself and must represent that it together with its affiliates is not voting (on a beneficial basis) more than 15% of the outstanding public warrants based on the most recent disclosure by Granite Ridge in a filing with the SEC of the outstanding amounts of public warrants unless Granite Ridge allows a holder to vote greater than 15%.

Certain Anti-Takeover Provisions of Delaware Law and the Certificate of Incorporation of the Granite Ridge

The Certificate of Incorporation of Granite Ridge provides that Granite Ridge is not subject to Section 203 of the DGCL. In general, Section 203 prohibits a publicly held Delaware corporation from engaging in a "business combination" with an

"interested stockholder" for a three-year period following the time that such stockholder becomes an interested stockholder, unless the business combination is approved in a prescribed manner. A "business combination" includes, among other things, a merger or consolidation, asset or stock sale, or other transaction resulting in a financial benefit to the interested stockholder. Subject to certain exceptions, an "interested stockholder" is a person who, together with affiliates and associates, owns, or did own within three years prior to the determination of interested stockholder status, 15% or more of the corporation's outstanding voting stock.

Under Section 203, a business combination between a corporation and an interested stockholder is prohibited unless it satisfies one of the following conditions:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced, excluding for purposes of determining the voting stock outstanding, shares owned by persons who are directors and also officers, and employee stock plans, in some instances; and
- on or after such time, the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

Classified Board

The Certificate of Incorporation and Bylaws of Granite Ridge provide for a classified board of directors consisting of three classes of directors, each serving staggered three-year terms (other than the initial Class I directors and Class II directors), as follows:

- The initial term of Granite Ridge's Class I directors will expire at Granite Ridge's 2023 annual meeting of stockholders.
- The initial term of Granite Ridge's Class II directors will expire at Granite Ridge's 2024 annual meeting of stockholders.
- The initial term of Granite Ridge's Class III directors will expire at Granite Ridge's 2025 annual meeting of stockholders.

Upon expiration of the term of a class of directors, directors for that class will be elected for three-year terms at the annual meeting of stockholders in the year in which that term expires. Each director's term continues until the election and qualification of his or her successor or his or her earlier death, resignation, or removal. Any increase or decrease in the number of directors will be distributed among the three classes so that, as nearly as possible, each class will consist of an equal number of directors.

Written Consent by Stockholders

The Certificate of Incorporation of Granite Ridge provides that for so long as the Grey Rock Entities (as defined in the Certificate of Incorporation) collectively hold at least a majority of the voting power of all then outstanding shares of capital stock of Granite Ridge, any action required or permitted to be taken at any annual or special meeting of the stockholders may be taken without a meeting, without prior notice and without a vote if a consent or consents in writing, setting forth the action so taken, is signed by the holders of such outstanding shares of capital stock of Granite Ridge having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Advance Notice Requirements for Stockholder Proposals and Director Nominations

The Bylaws of Granite Ridge provide that stockholders seeking to bring business before Granite Ridge's annual meeting of stockholders, or to nominate candidates for election as directors at Granite Ridge's annual meeting of stockholders, must provide timely notice of their intent in writing. To be timely, a stockholder's notice will need to be received by the company secretary at Granite Ridge's principal executive offices not earlier than the opening of business on the 120th day before the meeting and not later than the later of (x) the close of business on the 90th day before the meeting or (y) the close of business on the 10th day following the day on which public announcement of the date of the annual meeting is first made by Granite Ridge. Pursuant to Rule 14a-8 of the Exchange Act, proposals seeking inclusion in Granite Ridge's annual proxy statement must comply with the notice periods contained therein. The Bylaws also specify certain requirements as to the form and content of a stockholders' meeting. These provisions may preclude Granite Ridge's stockholders from bringing matters before Granite Ridge's annual meeting of stockholders or from making nominations for directors at Granite Ridge's annual meeting of stockholders.

Exclusive Forum

The Certificate of Incorporation of Granite Ridge provides that, unless Granite Ridge consents in writing to the selection of an alternative forum, that the Delaware Court of Chancery (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 behalf of Granite Ridge, any action asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of Granite Ridge, any action asserting a claim against Granite Ridge, its directors, officers or employees arising pursuant to any provision of the DGCL or Certificate of Incorporation or the Bylaws of Granite Ridge, or any action asserting a claim against Granite Ridge, its 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. Further, unless Granite Ridge consents in writing to the selection of an alternative forum, the federal district courts shall be the exclusive forum for any complaint arising under the Securities Act; however, there is uncertainty as to whether a court would enforce such provision. Any person or entity purchasing or otherwise acquiring an interest in Granite Ridge common stock will be deemed to have received notice of and consented to the foregoing forum selection provisions, which could limit Granite Ridge stockholders' ability to choose the judicial forum for disputes with Granite Ridge.

Transfer Agent and Warrant Agent

The transfer agent for the Granite Ridge common stock and warrant agent for the warrants is Continental Stock Transfer & Trust Company. Granite Ridge has agreed to indemnify Continental Stock Transfer & Trust Company in its roles as transfer agent and warrant agent, its agents and each of its stockholders, directors, officers, and employees against all claims and losses that may arise out of acts performed or omitted for its activities in those capacities, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Exchange Listing

Granite Ridge common stock and warrants are listed on the NYSE under the symbols "GRNT" and "GRNT WS," respectively.

Subsidiaries of the Registrant

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

Executive Network Partnering Corporation, a Delaware corporation

Granite Ridge Holdings, LLC, a Delaware limited liability company

Consent of Independent Registered Accounting Firm

We consent to the incorporation by reference in the registration statements of Granite Ridge Resources, Inc. on Form S-1 Registration Statement (File No. 333-268478) and Form S-8 (File No. 333-269036) of our report, dated March 27, 2023, on our audits of the consolidated financial statements of Granite Ridge Resources, Inc. as of December 31, 2022 and 2021, and for each of the years in the three-year period ended December 31, 2022, which report is included in this Annual Report on Form 10-K.

/s/ FORVIS, LLP

(Formerly, **BKD, LLP**)

Dallas, Texas

March 27, 2023



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 February 1, 2023, with respect to estimates of reserves and future net revenue to the Company's interest, as of December 31, 2022, in certain oil and gas properties located in North Dakota, Texas, Louisiana, Montana, Wyoming, Colorado, and New Mexico. We also hereby consent to all references to our firm or such report included in or incorporated by reference into such Annual Report, and thus incorporated by reference into the Registration Statement on Form S-1 (File No. 333-268478) (including any amendments or supplements thereto, related appendices, and financial statements) and the Registration Statement on Form S-8 (File No. 333-269036) of Granite Ridge Resources, Inc.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Eric J. Stevens

Eric J. Stevens, P.E.

President and Chief Operating Officer

Dallas, Texas
March 27, 2023

CERTIFICATION

I, Luke C. Brandenburg, certify that:

1. I have reviewed this annual report on Form 10-K of Granite Ridge Resources, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) (Paragraph omitted pursuant to SEC Release Nos. 33-8238/34-47986 and 33-8392/34-49313);
 - 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 27, 2023

By: /s/ LUKE C. BRANDENBERG

Luke C. Brandenburg
President and Chief Executive Officer

CERTIFICATION

I, Tyler S. Farquharson, certify that:

1. I have reviewed this annual report on Form 10-K of Granite Ridge Resources, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) (Paragraph omitted pursuant to SEC Release Nos. 33-8238/34-47986 and 33-8392/34-49313) ;
 - 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 27, 2023

By: /s/ TYLER S. FARQUHARSON

Tyler S. Farquharson
Chief Financial Officer

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

In connection with the Annual Report of Granite Ridge Resources, Inc., (the "Company") on Form 10-K for the period ended December 31, 2022, as filed with the United States Securities and Exchange Commission on the date hereof, (the "Report"), the undersigned officers of the Company hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of their knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 27, 2023

By: /s/ LUKE C. BRANDENBERG

Name: Luke C. Brandenburg

Title: *President and Chief Executive Officer*

Dated: March 27, 2023

By: /s/ TYLER S. FARQUHARSON

Name: Tyler S. Farquharson

Title: *Chief Financial Officer*

February 1, 2023

Mr. Luke Brandenburg
Granite Ridge Resources, Inc.
5217 McKinney Avenue, Suite 400
Dallas, Texas 75205

Dear Mr. Brandenburg:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2022, 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, 2022, to be:

Category	Net Reserves		Future Net Revenue (M\$)	
	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	15,375.9	89,418.0	1,571,784.7	1,008,786.0
Proved Developed Non-Producing	338.2	1,615.6	32,656.3	21,779.3
Proved Undeveloped	9,780.3	59,205.5	963,111.1	528,557.9
Total Proved	25,494.4	150,239.1	2,567,552.8	1,559,123.7

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 2022. For oil volumes, the average West Texas Intermediate spot price of \$94.14 per barrel is adjusted for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of \$6.357 per MMBTU is adjusted for energy content, transportation fees, and market differentials. 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 \$92.48 per barrel of oil and \$8.084 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 new development wells and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Granite Ridge's estimates of the costs to abandon the wells and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Granite Ridge interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Granite Ridge receiving its net revenue interest share of estimated future gross production. Additionally, we have made no specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical accounting statements.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance.

In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Granite Ridge, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts.

Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well location and acreage maps, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information

promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations; such reserves are based on analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Granite Ridge, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical person primarily responsible for preparing the estimates presented herein meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards.

Nathan C. Shahan, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2007 and has over 5 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

/s/ C.H. (Scott) Rees III

By:

C.H. (Scott) Rees III, P.E.
Executive Chairman

/s/ Nathan C. Shahan

By:

Nathan C. Shahan, P.E. 102389
Vice President

Date Signed: February 1, 2023

NCS:MBG

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2018 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

- (i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- (ii) Same environment of deposition;
- (iii) Similar geological structure; and
- (iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

- (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
- (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
- (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

- (iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
 - (iv) Provide improved recovery systems.
- (8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.
- (9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
- (10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.
- (11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.
- (12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
 - (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
 - (iii) Dry hole contributions and bottom hole contributions.
 - (iv) Costs of drilling and equipping exploratory wells.
 - (v) Costs of drilling exploratory-type stratigraphic test wells.
- (13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.
- (14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.
- (15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.
- (16) *Oil and gas producing activities*.
- (i) Oil and gas producing activities include:
 - (A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;
 - (B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;
 - (C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:
 - (1) Lifting the oil and gas to the surface; and
 - (2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

- a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and
- b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

- (A) Transporting, refining, or marketing oil and gas;
- (B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;
- (C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or
- (D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

- (i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.
- (ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.
- (iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
- (iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.
- (v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.
- (vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

- (i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

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.

