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

FORM 10-K

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

For the fiscal year ended December 31 , 2023

OR

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

Commission file number 001-15555

Riley Exploration Permian, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**87-0267438**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
29 E. Reno Avenue , Suite 500 Oklahoma City , Oklahoma	**73104**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code: **(405) 415-8699**

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common stock, par value $0.001	REPX	NYSE American

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

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

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 x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate web site, if any, every Interactive Data File required to be submitted and posted 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 and post such files). Yes x No o

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

Large accelerated filer	o	Accelerated filer	x
Non-accelerated filer	o	Smaller reporting company	x
		Emerging growth company	o

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. o

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. o

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 §240.1D-01(b). o

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

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 USC. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. x

Aggregate market value of the voting common equity held by non-affiliates of registrant as of June 30, 2023 was approximately $ 160.6 million.

The total number of shares of common stock, par value $0.001 per share, outstanding as of February 29, 2024 was 20,400,032 .

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report on Form 10-K ("Annual Report"), to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement relating to the Annual Meeting of Stockholders to be held in 2024, which definitive proxy statement shall be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report relates.

RILEY EXPLORATION PERMIAN, INC.

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

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DEFINITIONS

As used in this Annual Report, unless otherwise noted or the context otherwise requires, we refer to Riley Exploration Permian, Inc., together with its subsidiaries, as "Riley Permian," "REPX," "the Company," "Registrant," "we," "our," or "us." In addition, this Annual Report includes certain terms commonly used in the oil and natural gas industry, and the following are abbreviations and definitions of certain terms used within this Annual Report on Form 10-K:

Measurements.	
Bbl	One barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons
Boe	One stock tank barrel equivalent of oil, calculated by converting gas volumes to equivalent oil barrels at a ratio of 6 thousand cubic feet of gas to 1 barrel of oil and by converting NGL volumes to equivalent oil barrels at a ratio of 1 barrel of NGL to 1 barrel of oil
Boe/d	Stock tank barrel equivalent of oil per day
Btu	British thermal unit. One British thermal unit is the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit
MBbl	One thousand barrels of oil or other liquid hydrocarbons
MBoe	One thousand Boe
MBoe/d	One thousand Boe per day
Mcf	One thousand cubic feet of gas
MMBoe	One million Boe
MMBtu	One million British thermal units
MMcf	One million cubic feet of gas
Abbreviations.	
ARO	Asset Retirement Obligation
ATM	At-the-market equity sales program
BLM	Bureau of Land Management
CO_2	Carbon Dioxide
CWA	Clean Water Act
DD&A	Depreciation, depletion and amortization
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ESG	Environmental, social, and governance
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
IRS	Internal Revenue Service
NGA	Natural Gas Act of 1938
NGL	Natural gas liquids
NGPA	Natural Gas Policy Act of 1978
NMOCD	New Mexico Oil Conservation Division
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Oil	Crude oil and condensate
RRC	Railroad Commission of Texas
SEC	Securities and Exchange Commission
SOFR	Secured Overnight Financing Rate
SWD	Saltwater Disposal Well.
U.S. GAAP	Accounting principles generally accepted in the United States of America

WTI	West Texas Intermediate
Terms and Definitions.	
Developed oil and natural gas reserves	Developed oil and natural 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.
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.
Development well	A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.
Differential	An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
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 natural gas producing activities. The terminal point is generally regarded as the outlet valve on the lease or field storage tank.
Exploratory well	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 natural 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.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Play	A geographic area with hydrocarbon potential.
Proved oil and natural gas reserves	Proved oil and natural gas reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for estimation. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.
Proved undeveloped reserves	Proved undeveloped 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. 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. Undrilled locations can be classified as having proved 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. Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.
PV-10	The present value of estimated future gross revenue to be generated from the production of estimated net proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date indicated (unless such prices or costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, discounted using an annual discount rate of 10 percent. While this measure does not include the effect of income taxes as it would in the use of the standardized measure calculation, it does provide an indicative representation of the relative value of the applicable company on a comparable basis to other companies and from period to period.

Reserves	Reserves are estimated remaining quantities of oil and natural 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 natural gas or related substances to market and all permits and financing required to implement the project. 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).
Reserve additions	Changes in proved reserves due to revisions of previous estimates, extensions, discoveries, improved recovery, and other additions and purchases of reserves in-place.
Reserve life	A measure of the productive life of an oil or natural gas property or a group of properties, expressed in years.
Royalty interest	An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells 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.
Standardized measure	The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and natural gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves and deducting the estimated future costs to be incurred in developing, producing, and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rates with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and natural gas reserves.
Working interest	An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas from the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact, contained in this Annual Report that include information concerning our possible or assumed future results of operations, business strategies, need for financing, competitive position and potential growth opportunities represent management's beliefs and assumptions based on currently available information and they do not consider the effects of future legislation or regulations. Forward-looking statements include all statements that are not historical facts and can be identified by the use of forward-looking terminology such as the words “believes,” “intends,” “may,” “should,” “anticipates,” “expects,” “could,” “plans,” “estimates,” “projects,” “targets” or comparable terminology or by discussions of strategy or trends. Such statements by their nature involve risks and uncertainties that could significantly affect expected results, and actual future results could differ materially from those described in such forward-looking statements.

These forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those suggested by the forward-looking statements. Forward-looking statements should therefore be considered in light of various factors, including those set forth in this Annual Report under "Item 1A. Risk Factors," in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report. Because of such risks and uncertainties, we caution you not to place undue reliance on these forward-looking statements. These forward-looking statements speak only as of the date of this Annual Report, or if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities law.

SUMMARY RISK FACTORS

Risks Related to Our Business, Operations, and Strategy

- An extended decline in commodity prices may adversely affect our business, financial condition, results of operations, ability to meet our capital expenditure obligations and financial commitments, and the value of our reserves.
- We may be unable to obtain required capital or financing on satisfactory terms in order to fund our exploration and development projects, which could lead to a decline in our reserves.
- Our exploration and development efforts may not be profitable or achieve our targeted returns.
- Properties we acquire may not produce as projected, and may subject us to liabilities.
- Uncertainties could materially alter the occurrence or timing of drilling of our identified drilling locations.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate.
- We are vulnerable to risks associated with operating in one major geographic area.
- We may not be able to access on commercially reasonable terms or otherwise truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and natural gas production.
- Our estimated proved undeveloped reserves may not be ultimately developed or produced if their development is costlier or more time consuming than expected.
- We may be unable or fail to successfully integrate acquired assets into our operations and development activities.
- There may be potential delays in the development, construction or start-up of planned projects.
- Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline.
- Our undeveloped acreage must be drilled before lease expirations to hold the acreage by production, which could result in a substantial lease renewal cost or loss of our lease and prospective drilling opportunities.
- Funding through capital market transactions may be difficult and expensive due to our small public float, low market capitalization, and limited operating history.
- Covenants in our revolving credit facility ("Credit Facility") may restrict our business and financing activities and our ability to declare dividends.
- We may not be able to generate sufficient cash to service all of our indebtedness.
- Our derivative activities could result in financial losses or could reduce our earnings.

Risks Related to the Oil and Natural Gas Industry

- Conservation measures, alternative sources of energy and technological advances could reduce demand for oil, natural gas and NGLs.
- Shortages or cost increases related to equipment, supplies or qualified personnel could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.
- Negative public perception regarding us and/or our industry could have an adverse effect on our operations.
- General domestic and international economic, market and political conditions, including the military conflict between Russia and Ukraine, the Israel-Hamas conflict, and the global response to such conflicts may negatively impact us.

Risks Related to Public Health, Acts of God, and Cybersecurity

- Our business and operations may be adversely affected by public health crises, such as pandemics and epidemics.
- Power outages or limits and increased energy costs could have a material adverse effect on us.
- Extreme weather conditions could adversely affect our business and operations.
- Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

Risks Related to Legal, Regulatory, and Tax Matters

- Regulations related to environmental and occupational health and safety issues could adversely affect the cost, manner or feasibility of conducting our operations.
- We are responsible for the decommissioning, plugging, abandonment, and reclamation costs for our facilities.
- Increased regulation of our oil and natural gas assets could cause our revenues to decline and operating expenses to increase.
- Regulatory initiatives relating to hydraulic fracturing, regulation of greenhouse gases, water conservation, seismic activity, weatherization, or protection of certain species of wildlife, or of sensitive environmental areas could result in increased costs and/or decreased production.
- New or increased taxes or fees on oil and natural gas extraction or production or changes in our effective tax rate, could adversely impact us.

Risks Related to Our Common Stock

- The market price of our common stock may be volatile, which could cause the value of an investment in our stock to decline.
- If we fail to continue to meet NYSE American listing requirements, our common stock could be delisted from trading, which would decrease the liquidity of our common stock and ability to raise additional capital.
- Our quarterly cash dividends, if any, may vary significantly both quarterly and annually.
- Our Board of Directors may modify or revoke our dividend policy at any time at its discretion.
- Available cash for dividends depends primarily on our cash flow and not solely on our profitability, which may prevent us from paying dividends, even during periods in which we record net income.

Risks Related to the Company

- Our business and operations could be adversely affected if we lose key personnel.
- Our executive officers, directors and principal stockholders have the ability to control or significantly influence all matters submitted to the Company’s stockholders for approval.
- Conflicts of interest could arise in the future between us, on the one hand, and certain of our stockholders and their respective affiliates.

PART I

Items 1 and 2. Business and Properties

Overview

Riley Exploration Permian, Inc., together with its wholly-owned subsidiaries, is a growth-oriented, independent oil and natural gas company focused on the acquisition, exploration, development and production of oil, natural gas and NGLs in Texas and New Mexico. The majority of our acreage is located in Yoakum County, Texas and Eddy County, New Mexico.

We focus on horizontal drilling and completions applied to conventional formations in the Permian Basin. Our principal business objective is to deliver long-term shareholder value by development of our existing assets and continuous improvement of our operating capabilities and cost structure by utilizing our extensive technical expertise. We also look for opportunities to add to our drilling inventory through acquisitions that meet our strategic and financial objectives. We believe such growth and corresponding increase in scale can lead to additional operating cost efficiencies.

Management prioritizes corporate sustainability and positioning the Company for success in both the near-term and long-term with initiatives focused on existing business and the transitioning energy landscape. Our strategic objectives include enhancing the rate of return on our invested capital, generating sustainable free cash flow, maintaining a strong and flexible balance sheet and maximizing returns to our shareholders. We implement this strategy primarily through identification and capture of attractive development opportunities, optimization of our assets and operations and continuous improvement of our cost structure.

In August 2022, the Company's Board of Directors (the "Board") and holders of approximately 75% of our outstanding common stock acting by written consent resolved to amend and restate the Company's Second Amended and Restated Bylaws to change the Company's fiscal year period from October 1st through September 30th each year to January 1st through December 31st each year commencing with the 2022 calendar year. As a result, the Company's 2022 fiscal year was the period from January 1, 2022 to December 31, 2022. However, the fiscal year information for 2021 included here reflects the twelve months ended September 30, 2021.

2023 Acquisition

On April 3, 2023, the Company completed its acquisition of oil and natural gas assets in the Yeso trend of the Permian Basin in Eddy County New Mexico (the "New Mexico Acquisition") from Pecos Oil & Gas, LLC ("Pecos"), a Delaware limited liability company and an affiliate of Cibolo Energy Partners, LLC, for an adjusted purchase price of $325 million, reflective of customary post-closing adjustments. See Note 4 - Acquisitions of Oil and Natural Gas Properties in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a full discussion of this acquisition.

The Company funded the New Mexico Acquisition through a combination of borrowings under the Company's revolving credit facility ("Credit Facility") and proceeds from the issuance of $200 million of unsecured senior notes ("Senior Notes"). See Note 9 - Long-Term Debt in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a full discussion of our long-term debt.

Our Properties

The Permian Basin is an oil and natural gas producing area located in West Texas and the adjoining area of Southeastern New Mexico covering an area approximately 250 miles wide and 300 miles long, and encompasses several sub-basins, including the Delaware Basin, Midland Basin, Central Basin Platform and Northwest Shelf. The San Andres Formation is a shelf margin deposit composed of dolomitized carbonates.

Our acreage is primarily located on large contiguous blocks in Yoakum County, Texas, which represents our Champions Field and Eddy County, New Mexico, which represents our Redlake Field acquired in the New Mexico Acquisition. Riley Permian’s acreage in Yoakum County offsets legacy Permian Basin San Andres fields, including the Wasson and Brahaney Fields, which have produced more than 2.1 billion barrels of oil equivalent and 109 million barrels of oil equivalent, respectively, from the San Andres Formation since development in the area began in the 1930s and 1940s. We believe the horizontal San Andres wells we and offset operators have drilled to date have delineated our acreage. In Eddy County, New Mexico, our acreage offsets legacy Permian Basin Abo, Yeso, and San Andres Fields, including the Redlake and Loco Hills Fields, which have produced more than 42 million barrels of oil equivalent and 32 million barrels of oil equivalent, respectively, from the Yeso Formation since development in the area began in 2007 and 2008. Based on the close proximity to these productive fields, combined with the horizontal Yeso wells we and offset operators have drilled to date, we believe we have significantly delineated our acreage.

As of December 31, 2023, we had 44,056 net acres and a total of 402 net producing wells. We operated 96% of our net production for the year ended December 31, 2023 and have an average working interest of 93% in our operated wells. Our average net daily production during the year ended December 31, 2023 was approximately 18,590 Boe/d.

Oil, Natural Gas and NGL Reserves

Summary of Oil, Natural Gas and NGL Reserves

The following table summarizes the Company's estimated proved reserves as of December 31, 2023 and 2022.

	December 31,	
	2023	**2022**
Proved Developed Producing Reserves: [1]		
Oil (MBbls)	36,731	29,632
Natural Gas (MMcf)	71,671	59,314
NGLs (MBbls)	11,502	9,604
Proved Developed Producing Reserves (MBoe)	60,178	49,122
Proved Undeveloped Reserves:		
Oil (MBbls)	29,577	19,250
Natural Gas (MMcf)	52,277	26,704
NGLs (MBbls)	9,247	4,850
Proved Undeveloped Reserves (MBoe)	47,537	28,551
Total Proved Reserves:		
Oil (MBbls)	66,308	48,882
Natural Gas (MMcf)	123,948	86,018
NGLs (MBbls)	20,749	14,454
Total Proved Reserves (MBoe)	107,715	77,673

(1) Total proved reserves were comprised of 56% and 63%, respectively, of total proved developed producing reserves as of December 31, 2023 and 2022.

Estimates of reserves were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2023 and 2022 in accordance with SEC guidelines. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties, all of which are located within the continental United States. See "Item 1A. Risk Factors" for a discussion of risks and uncertainties associated with our estimates of proved reserves and related factors, and see Note 15 - Supplemental Oil and Gas Information in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a full discussion of our reserve estimates and pricing.

Proved Undeveloped Reserves (PUDs)

The following table summarizes changes in the Company's estimated PUDs for the year ended December 31, 2023 (in MBoe):

Proved undeveloped reserves at December 31, 2022	28,551
Acquisitions	13,559
Conversions	(3,378)
Extensions and discoveries	14,543
Revisions	(5,738)
Proved undeveloped reserves at December 31, 2023	47,537

During the year ended December 31, 2023, we acquired 13.6 MMBoe of proved undeveloped reserves, primarily from the New Mexico Acquisition, and incurred costs of approximately $32.5 million to convert 3.4 MMBoe of proved undeveloped reserves to proved developed reserves. Our extensions and discoveries of 14.5 MMBoe were primarily the result of drilling activity during the year, which allowed for offset PUDs. Additionally, we had downward revisions of 5.7 MMBoe. These downward revisions were primarily attributable to the removal of PUDs due to changes in our development schedule, and to a lesser extent increases in estimated operating costs and capital expenditures and decreases in well-level projections in certain undeveloped areas. Consistent with SEC guidelines, PUDs are limited to those locations that are reasonably certain to be developed within five years.

PUDs will be converted from undeveloped to developed with successful development and as the applicable wells begin production. As of December 31, 2023, all of the Company's proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. Estimated costs relating to the future development of the Company's proved undeveloped reserves at December 31, 2023 were approximately $322.7 million, which we expect to finance through cash flow from operations, borrowings under our Credit Facility and other sources of capital.

Evaluation and Review of Reserves

Our reserve estimates as of December 31, 2023, which we refer to as the Reserve Report, were prepared based on a report by Ryder Scott Company L.P. ("Ryder Scott"), our independent petroleum consulting firm. The technical person primarily responsible for overseeing the preparation of the estimates is our Reservoir Engineering Manager. Our Reservoir Engineering Manager has over 15 years of industry experience, a degree in petroleum engineering, and is a registered professional engineer. Within Ryder Scott, the primary technical person responsible for preparing the estimates set forth in the Reserve Report is Mr. Scott James Wilson, a licensed professional engineer in the states of Alaska, Colorado, Texas, and Wyoming. Mr. Wilson has been a practicing petroleum engineering consultant at Ryder Scott since 2000 and is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluations studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. He earned a Bachelor of Science degree in petroleum engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with high honors. Mr. Wilson 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. Ryder Scott does not own an interest in any of the Company's properties, nor is it employed by us on a contingent basis.

Internal Controls

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate the Company's reserves. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the Reserve Report to discuss the assumptions and methods used in the proved reserve estimation process. The qualifications of the technical persons primarily responsible for overseeing the preparation of the estimates of our reserves are set forth in "— Evaluation and Review of Reserves" above. We provided historical information to the independent reserve engineers for the Company's properties, such as ownership interest, oil and natural gas production, well test data, commodity prices, and operating and development costs.

The preparation of the Company's reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by the Company;
- communicating, collaborating, and analyzing with technical personnel in the Company's Operating and Business departments;
- preparation of reserve estimates by the Company's Reservoir Engineering Manager or under her direct supervision;
- comparing and reconciling the internally generated reserves estimates to those prepared by third parties;
- confirming completeness of reserve estimates for all properties owned and verification of the use of the proper working and net revenue interests; and
- no employee's compensation is tied to the amount of reserves booked.

Estimation of Proved Reserves

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2023 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. 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. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, historical well cost and operating expense data.

Drilling, Acreage, and Development Activities

Drilling Results

The following table sets forth information with respect to the number of total gross and net oil wells completed by us during the periods indicated. We do not have any natural gas wells, therefore the information set forth in the table below only pertains to oil wells. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return. The following table presents our development and exploratory drilling results for the years ended December 31, 2023 and 2022 and the fiscal year ended September 30, 2021:

	Year Ended December 31,				Year Ended September 30,	
	2023		2022		2021	
	Gross	Net[1]	Gross	Net[1]	Gross	Net[1]
Development Wells:						
Productive	24	18.2	17	13.8	18	13.2
Dry	—	—	—	—	—	—
Exploratory Wells:						
Productive	—	—	—	—	2	1.2
Dry [2]	—	—	—	—	—	—
Total Wells:						
Productive	24	18.2	17	13.8	20	14.4
Dry	—	—	—	—	—	—

(1) Net wells are gross wells multiplied by our fractional working interest.

(2) Excludes an exploratory well suspended as of September 30, 2021 and subsequently expensed in the fourth quarter of 2023.

As of December 31, 2023, we had 8 gross (8 net) wells in the process of drilling or active completions stages.

We operated 96% of our production for the year ended December 31, 2023. As operator, we design and manage the development of our wells and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all of the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Acreage Statistics

The following table sets forth our gross and net acres of developed and undeveloped leasehold as of December 31, 2023:

Developed Acreage[1]		Undeveloped Acreage[2]		Total Acreage	
Gross[3]	Net[4]	Gross[3]	Net[4]	Gross[3]	Net[4]
56,296	41,189	5,522	2,867	61,818	44,056

(1) Developed acreage is acres spaced or assigned to productive wells.

(2) Undeveloped acreage are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves.

(3) The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interest in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole and fractions thereof.

Approximately 93% of our total net acreage is held by production and 1% is held by obligations. For acreage that is not held by production, unless production is established within the spacing units covering the remaining acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates, the leases will expire in accordance with their respective terms. Substantially all of the leases governing our acreage have continuous development clauses that permit us to continue to hold the acreage under such leases after the expiration of the primary term if we initiate additional development within 120 to 180 days after the completion of the last well drilled on such lease, without the requirement of a lease extension payment. Thereafter, the lease is held with additional development every 120 to 240 days, and generally 180 days, until the entire lease is held by production. None of the Company's horizontal drilling locations associated with proved undeveloped reserves are scheduled for drilling outside of a lease term that is not accounted for with a continuous development schedule or primary term.

The following table sets forth the net undeveloped acreage, as of December 31, 2023 that will expire over the next three years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

Net Undeveloped Acreage		
2024	2025	2026
1,190	977	552

Based on our current development plans, we expect to maintain substantially all of the acreage that would otherwise expire during 2024 either through drilling and establishing production, making lease extension payments, or lease renewal efforts. Approximately 79% of our net undeveloped acreage for 2024 is currently held by continuous drilling and established production. We intend to extend or renew any lease we plan to develop or are still assessing for development that is set to expire in 2024. Given our currently planned drilling activities, we do not expect the amount of any such lease extension payments to be material. Additionally, our Texas acreage is 100% fee leasehold, while our New Mexico acreage is approximately 50% fee and state leasehold with the remaining 50% consisting of BLM leasehold.

Development Opportunities

The Company has a long history in the Permian Basin. In evaluating and determining drilling locations, we also consider the availability of local infrastructure, drilling support assets, property restrictions and state and local regulations. The drilling locations that we actually drill will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors, and may differ from the locations currently identified.

Oil, Natural Gas and NGL Production, Production Prices and Production Costs

Production and Operating Data

The Company has two fields that represent 15% or more of the Company's total reserves: Champions Field and Redlake Field. The Company's additional acreage is included in the below table as Other. The following tables set forth information regarding the Company's production, average realized prices and production costs for the years ended December 31, 2023 and 2022 and the fiscal year ended September 30, 2021.

	Year Ended December 31,		Year Ended September 30,
	2023	2022	2021
Production Data:			
Oil (MBbls)			
Champions	3,658	3,075	2,243
Redlake	930	—	—
Other	214	142	97
Total	4,802	3,217	2,340
Natural gas (MMcf)			
Champions	3,589	3,198	2,566
Redlake	2,179	—	—
Other	97	31	36
Total	5,865	3,229	2,602
NGLs (MBbls)			
Champions	526	435	372
Redlake	451	—	—
Other	29	9	8
Total	1,006	444	380
Total (MBoe)			
Champions	4,783	4,043	3,043
Redlake	1,744	0	0
Other	259	156	111
Total	6,786	4,199	3,154
Daily combined volumes (Boe/d)			
Champions	13,102	11,077	8,336
Redlake	4,779	—	—
Other	709	428	304
Total	18,590	11,505	8,640
Daily oil volumes (Bbls/d)			
Champions	10,022	8,425	6,145
Redlake	2,548	—	—
Other	586	389	266
Total	13,156	8,814	6,411

	Year Ended December 31,		Year Ended September 30,
	2023	2022	2021
Average Prices:			
Oil ($ per Bbl)	$ 75.62	$ 92.86	$ 58.29
Natural gas ($ per Mcf) (1)	0.45	3.33	2.88
NGLs ($ per Bbl) (1)	6.87	22.22	12.41
Combined ($ per Boe)	$ 54.91	$ 76.05	$ 47.12
Average Prices, including derivative settlements:			
Oil ($ per Bbl)	$ 71.93	$ 71.75	$ 51.47
Natural gas ($ per Mcf) (1)	0.53	1.06	2.75
NGLs ($ per Bbl) (1)	6.87	22.22	12.41
Combined ($ per Boe)	$ 52.38	$ 58.13	$ 41.95
Average Operating Costs per Boe:			
Lease operating expenses	$ 8.67	$ 7.73	$ 6.97
Production and ad valorem taxes	$ 3.77	$ 4.59	$ 2.74

(1) The Company's natural gas and NGL sales are presented net of gathering, processing and transportation fees which can result in negative average prices.

As a result of our drilling and completion activity as well as our New Mexico Acquisition, we increased our average net production from 11,505 Boe/d for the year ended December 31, 2022 to an average net production of 18,590 Boe/d for the year ended December 31, 2023. During the year ended December 31, 2023, our production was approximately 71% oil, 14% natural gas and 15% NGLs.

Productive Wells

As of December 31, 2023, we produced from 517 gross (402 net) total wells, which includes both operated and non-operated wells.

Producing Wells	Gross Wells	Average Working Interest
Operated	420	93 %
Non-Operated	97	15 %

Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which the Company has an interest, operated and non-operated, and net wells are the sum of our fractional working interests owned in gross wells.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient right-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest generally ranging from 75% to 80%.

Marketing and Customers

We market the majority of the production from properties we operate for both our account and the account of the other working interest owners in these properties.

We sell our production at market prices and to a relatively small number of purchasers, as is customary in the exploration, development and production business. Our purchaser contracts include marketing provisions with our purchasers to market our production. For the years ended December 31, 2023 and 2022 one purchaser accounted for 70% and 89%, respectively, of our revenue purchased. For the year ended December 31, 2023, an additional purchaser accounted for 10% or more of our revenues. During the year ended December 31, 2022, no other purchaser accounted for 10% or more of our revenues. The loss of either of these purchasers could materially and adversely affect our revenues in the short-term. Further, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any of our purchasers would not have a long-term material adverse effect on our financial condition and results of operations because oil and natural gas are fungible products with well-established markets.

Transportation

We consider all gathering and delivery infrastructure in conjunction or ahead of development of an area. We strive to install such infrastructure ahead of first production to mitigate flaring and reduce operating costs. Our oil is collected from the wellhead to our tank batteries and then transported by the purchaser by truck or lease automatic custody transfer or LACT meter and delivered to another pipeline or a refinery. A portion of our natural gas is transported from the wellhead to the purchaser’s meter and pipeline interconnection point. In addition, we move substantially all of our produced water by pipeline connected to company-owned SWDs rather than by truck. Given the amount of disposal water volume, the connection to SWDs helps us reduce our lease operating expenses.

We are currently a party to a crude oil pipeline transportation agreement with Stakeholder Midstream Crude Oil Pipeline, LLC ("Stakeholder Midstream"). We believe we benefit from relatively low take-away costs as compared to transportation by truck, which also has the benefits of reducing truck traffic and related emissions. In 2022, the Company amended its gas gathering and processing agreement with Stakeholder Midstream to reflect Stakeholder Midstream's commitment to expand their gathering and processing system with a commitment from the Company to deliver an annual minimum volume to Stakeholder Midstream's gathering system for at least seven years beginning on the in-service date of the expanded plant, which occurred in 2023. While the minimum volume commitment is below our forecasted production, there are financial penalties if the minimum activity levels are not met. We did not incur any such penalties during 2023. The additional capacity from the gas processing plant expansion has resulted in increased natural gas volumes processed and decreased gas flaring for the Company.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Some of our competitors possess and employ financial resources substantially greater than ours and some competitors employ more technical personnel. These factors can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects, and to evaluate, bid for, and purchase a greater number of properties and prospects than what our financial or technical resources permit. Our ability to acquire additional properties and to find and develop reserves in the future will depend on our ability to identify, evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil, natural gas and NGLs. Demand for oil, natural gas and NGLs is typically higher in the fourth and first calendar quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Regulation of the Oil and Natural Gas Industry

REPX's operations are substantially affected by federal, tribal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which REPX owns or operates producing oil and natural gas properties have statutory provisions regulating the development and production of oil and natural gas, including, for example, provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, decommissioning and removal of equipment, and the plugging and abandonment of wells. REPX's operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting and regulate the flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. State laws, including those in Texas and New Mexico, govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that REPX can produce from its wells and to limit the number of wells or the locations at which REPX can drill, although REPX can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, Texas and New Mexico impose a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within their jurisdictions.

Failure to comply with applicable laws and regulations can result in substantial penalties and delays in development. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although REPX believes it is in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, REPX is unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, FERC and the courts. REPX cannot predict when or whether any such proposals may become effective. REPX does not believe that it would be affected by any such action materially different than similarly situated competitors.

Regulation Affecting Production

The production of oil and natural gas is subject to United States federal and state laws and regulations, and orders of regulatory bodies under those laws and regulations, governing a wide variety of matters. All of the jurisdictions in which REPX owns or operates producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including, for example, provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, 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 drilling and completion process, decommissioning and removal of equipment, and the plugging and abandonment of wells. REPX's operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the amount of oil and natural gas wells REPX can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from REPX's wells, negatively affect the economics of production from these wells or limit the number of locations at which REPX can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations can result in substantial penalties. REPX's competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect REPX's operations.

Regulation of Sales and Transportation of Oil

Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Although prices of these energy commodities are currently unregulated, the United States Congress historically has been active in their regulation. REPX cannot predict whether new legislation to regulate oil and NGLs, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on REPX's operations. Additionally, such sales may be subject to certain state, and potentially federal, reporting requirements.

REPX's sales of oil are affected by the availability, terms and cost of transportation. Prices received from the sale of crude oil and NGLs may be affected by the cost of transporting those products to market. FERC has jurisdiction under the Interstate Commerce Act ("ICA"), as it existed in 1977, over common carriers engaged in the transportation in interstate commerce by pipeline of crude oil, NGLs and refined petroleum products as part of the continuous movement of the crude oil, NGLs or refined petroleum products in interstate commerce. The ICA requires that pipelines providing jurisdictional movements maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service be "just and reasonable." In general, interstate oil pipeline rates must be cost-based, although indexed rates, settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

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 and regulations regarding access are equally applicable to all comparable shippers, REPX believes that the regulation of oil transportation will not affect REPX's operations in any way that is of material difference from those of REPX's competitors who are similarly situated.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. 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 uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA, and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the NGA, and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The Energy Policy ("EP") Act of 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful: (i) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (ii) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704, described below. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, any market participant that engages in wholesale sales or purchases of natural gas that equal or exceed 2,200,000 MMBtus of physical natural gas in the previous calendar year, including natural gas producers, gatherers and marketers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices to FERC on Form No. 552. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities are done on a case by case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, or vice versa, and depending on the scope of that decision, REPX's costs of getting natural gas to point of sale locations may increase. REPX believes that the natural gas pipelines in the gathering systems REPX uses meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation by FERC as an interstate transmission company. However, the distinction between FERC-regulated transmission services and gathering services unregulated by FERC is the subject of ongoing litigation, so the classification and regulation of the gathering facilities REPX owns and uses are subject to change based on future determinations by FERC, the courts or Congress. Federal and state regulation of natural gas gathering facilities generally includes various occupational health and safety, environmental and, in some circumstances, nondiscriminatory take requirements. At the state level, natural gas gathering operations may receive even greater regulatory scrutiny, such as being subject to complaint-based rate regulation, and various safety and operational regulations relating to the design, construction, testing, operation, replacement, removal, remediation and maintenance of gathering facilities.

The price at which REPX sells natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to REPX's physical sales of these energy commodities, REPX is required to observe anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and under the Commodity Exchange Act ("CEA"), and regulations promulgated thereunder by the Commodity Futures Trading Commission ("CFTC"). The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. Should REPX violate the anti-market manipulation laws and regulations, REPX could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. 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, REPX believes that the regulation of similarly situated intrastate natural gas transportation in any states in which REPX operates and ships natural gas on an intrastate basis will not affect REPX's operations in any way that is of material difference from those of REPX's competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that REPX produces, as well as the revenues REPX receives for sales of its natural gas.

Changes in law and to FERC or state policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and REPX cannot predict what future action FERC or state regulatory bodies will take. REPX does not believe, however, that any regulatory changes will affect REPX in a way that materially differs from the way they will affect other natural gas producers and marketers with which REPX competes.

Regulation of Environmental and Occupational Safety and Health Matters

REPX's oil and natural gas development operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health, the discharge of materials into the environment or otherwise relating to environmental and human health protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may (i) require the acquisition of a permit before drilling or other regulated activity commences; (ii) restrict the types, quantities and concentrations of various substances that can be released into the environment; (iii) govern the sourcing and disposal of produced water used in the drilling and completion process; (iv) limit or prohibit drilling or other operational activities in certain areas and on certain lands lying within wilderness, wetlands, frontier, threatened or endangered species habitat and other protected areas; (v) require some form of remedial action to clean up, prevent or mitigate pollution from former operations such as plugging abandoned wells, decommissioning and removing abandoned surface equipment, or closing earthen pits; (vi) establish specific safety and health criteria addressing worker protection; (vii) impose substantial liabilities for pollution resulting from operations or failure to comply with regulations, including permitting requirements; (viii) require the installation of costly emission monitoring and/or pollution control equipment; (ix) require the preparation and implementation of oil spill prevention, control, and countermeasure plans and risk management plans; and (x) require the reporting of the types and quantities of various substances that are generated, stored, processed, released, or disposed of in connection with REPX's properties. In addition, these laws and regulations may restrict the rate of production. Failure to comply with these laws and regulations may result in the assessment of substantial administrative, civil, and criminal penalties, as well as possible issuance of injunctions limiting or prohibiting REPX's activities.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which REPX's business operations are subject and for which compliance may have a material adverse impact on REPX's capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of persons that own or owned property where release of a "hazardous substance" occurred or are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and anyone who disposed, transported, or arranged for the transport or disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for certain health studies. In addition, from time to time, EPA may designate additional materials as hazardous substances under CERCLA, which could result in the listing of new Superfund sites, additional investigation and remediation at current Superfund sites, or in the reopening of Superfund sites that previously received regulatory closure. For example, on August 26, 2022, EPA announced a proposal to designate as hazardous substances under CERCLA both perfluorooctanoic acid ("PFOA") and perfluorooctanesulfonic acid ("PFOS"), each of which has been commonly used in a variety of industrial and consumer products. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. REPX generates materials in the course of REPX's operations that may be regulated as "hazardous substances". REPX is able to control directly the operation of only those wells with respect to which REPX acts as operator. Notwithstanding REPX's lack of direct control over wells operated by others, the failure of an operator other than REPX to comply with applicable environmental regulations or the failure of a facility receiving hazardous substances for treatment or disposal to manage the substances properly may, in certain circumstances, be attributed to REPX and result in CERCLA or comparable federal or state liability.

The Resource Conservation and Recovery Act ("RCRA") and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA currently specifically excludes drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address EPA's alleged failure to timely assess RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree required EPA to propose a rulemaking no later than March 15, 2019 for revision of the Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. EPA ultimately concluded that revision of the Subtitle D criteria regulations regarding oil and natural gas wastes was not necessary at that time. But, should future rulemakings or legal challenges result in a loss of the RCRA hazardous-waste exclusion for drilling fluids, produced waters and related wastes, REPX's costs to manage and dispose of generated wastes could increase, which could have a material adverse effect on REPX's results of operations and financial position. In addition, in the course of REPX's operations, REPX generates some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes are listed as hazardous wastes or have hazardous characteristics.

REPX currently owns, leases or operates numerous properties that have been used for oil and natural gas development and production activities for many years. Although REPX believes that it has utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by REPX, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling, treatment or disposal. In addition, some of REPX's properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under REPX's control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, REPX could be required to undertake response or corrective measures, which could include investigation of the nature and extent of contamination, removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging, decommissioning and surface equipment removal, or pit closure operations to prevent future contamination.

Water Discharges

The Federal Clean Water Act ("CWA") and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into or near navigable and other regulated waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the "USACE"). Whether CWA permitting is required depends upon whether and the extent to which "Waters of the United States" ("WOTUS") may be impacted by the planned activity—for example, construction of drilling pads, access roads, or pipelines. Rulemaking by EPA and the USACE to define WOTUS has been heavily litigated, resulting in the rule taking effect at times in some states but not others and creating definitions that are more inclusive of certain waters effective in some states and those that are less inclusive effective in other states. EPA's and USACE's WOTUS definition rulemaking published in the Federal Register on January 18, 2023 (the January 2023 Rule) incorporated "relatively permanent" and "significant nexus" standards for determining jurisdiction over adjacent wetlands and additional waters, thereby expanding the types of waters that could be considered WOTUS. However, this WOTUS definition was litigated and eventually amended on August 29, 2023, when EPA and USACE issued a final rule to conform the WOTUS definition to the U.S. Supreme Court's May 25, 2023, decision in *Sackett v. Environmental Protection Agency*, which invalidated parts of the January 2023 Rule. With the August 2023 rulemaking, EPA and USACE implemented a narrower definition of WOTUS by, for example, removing "interstate wetlands"; redefining "adjacent" to mean "having a continuous surface connection"; and removing the "significant nexus" standard from the provisions regarding tributaries, adjacent wetlands, and intrastate lakes and ponds. To the extent any litigation or future amendments to the rule expand the scope of the Clean Water Act's jurisdiction, REPX could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas or in connection with stream crossings and preparation and implementation of oil spill prevention, control, and countermeasure ("SPCC") plans.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. In addition, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses a substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect REPX's operations.

SPCC regulations promulgated under the CWA and later amended by the Oil Pollution Act of 1990 require 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, to develop, implement, and maintain an SPCC plan. The SPCC plan must describe oil handling operations, spill prevention practices, discharge or drainage controls, and the personnel, equipment and resources at the facility that are used to prevent oil spills from reaching navigable and other regulated waters or adjoining shorelines, and reviewed at least every five years.

Pursuant to CWA laws and regulations, REPX may also be required to obtain and maintain approvals or permits for the discharge of wastewater, including produced water, or storm water. Obtaining permits has the potential to delay the development of oil and natural gas projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances and may impose substantial potential liability for the costs of removal, remediation and damages.

Subsurface Injections

In the course of REPX's operations, REPX produces water in addition to oil and natural gas. Water that is not recycled may be disposed of in disposal wells, which inject the produced water into non-producing subsurface formations. Underground injection operations are regulated pursuant to the Underground Injection Control ("UIC") program established under the U.S. Safe Drinking Water Act ("SDWA") and analogous state laws. The UIC program requires permits from the EPA or state agency to which the UIC program has been delegated for the construction and operation of disposal wells, establishes minimum standards for disposal well operations, and restricts the types and quantities of fluids that may be disposed. A change in UIC disposal well regulations or the inability to obtain permits for new disposal wells in the future may affect REPX's ability to dispose of produced water and ultimately increase the cost of REPX's operations. For example, in response to recent seismic events below ground near disposal wells used for the injection of oil and natural gas-related wastewaters, regulators in some states, including Texas and New Mexico, have imposed more stringent permitting and operating requirements for produced water disposal wells. Both the RRC and NMOCD have policies and rules 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 and NMOCD may deny, modify, suspend or terminate the permit application or existing operating permit for that well. In certain cases operators may be required to reduce, and in some cases even suspend, injection operations when proximate induced seismicity exceeds certain thresholds. Additionally, legal disputes may arise based on allegations that disposal well operations have caused damage to neighboring properties or otherwise violated state or federal rules regulating waste disposal. These developments could result in additional regulation, restriction on the use of injection wells by REPX or by commercial disposal well vendors whom REPX may use from time to time to dispose of wastewater, and increased costs of compliance, which could have a material adverse effect on REPX's capital expenditures and operating costs, financial condition, and results of operations.

In addition, several cases have recently 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 split among federal circuit courts of appeals that decided these cases engendered two petitions for writ of certiorari to the United States Supreme Court in August 2018, one of which was granted in February 2019. 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 April, 2020, the Supreme Court issued a ruling in the case, *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. In April 2019, before the Supreme Court ruling, EPA issued an Interpretive Statement and additional Request for Comment and, following the ruling, in January 2021, new guidance on the ruling, but that guidance was later rescinded by EPA. On November 20, 2023, EPA issued draft guidance outlining the factors that may be considered when evaluating whether discharges through groundwater may be the "functional equivalent" of a direct discharge, and thereby subject to regulation under the CWA National Pollutant Discharge Elimination System Permit Program (which permits point sources to discharge specified amounts of pollutant(s) to waters of the United States under specified conditions, and describes the types of information that should be used in determination). Comments on the draft guidance were due to the agency by December 27, 2023, and to date EPA has not finalized the guidance. The U.S. Supreme Court's ruling in *County of Maui, Hawaii v. Hawaii Wildlife Fund* could result in increased operational costs for REPX if permits are required under the CWA for disposal of REPX's flowback and produced water in disposal wells.

Air Emissions

The Federal Clean Air Act ("CAA") and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require REPX to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, REPX may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard, (" NAAQS") for ozone from 75 to 70 parts per billion and, more recently, on August 21, 2023, EPA announced the initiation of a new review of the ozone NAAQS to ensure the standards reflect the most current, relevant science. Implementation of revised NAAQS by Texas and New Mexico could result in stricter permitting requirements, delay or prohibit REPX’s ability to obtain required permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, beginning in 2012, the EPA adopted new rules under the CAA that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas and, in 2016, oil wells for which well completion operations are conducted (i.e., use reduced emission completions, also known as “green completions”), referred to as New Source Performance Standards ("NSPS") subparts OOOO and OOOOa, respectively. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, pneumatic controllers, storage vessels, and under the NSPS Subpart OOOOa regulations, well-site components (fugitive emissions). More recently, EPA, in December 2023, announced additional final NSPS OOOO program final rules—referred to as Subparts OOOOb and OOOOc—which, once effective upon publication in the Federal Register, are expected to have a significant impact on the upstream and midstream oil and gas sectors from an operational cost perspective. The rules impose additional methane and VOC emissions limitations from new, modified, and reconstructed sources, and will regulate existing sources for the first time under the NSPS OOOOc program by requiring states to implement plans that meet or exceed federally established emission reduction guidelines for existing oil and natural gas facilities. Although the bulk of the 2012 and 2016 standards are currently in effect, future implementation and the ultimate scope of VOC and methane emissions for the oil and gas production, transmission, and storage industry segments are uncertain at this time and could be modified further as a result of ongoing rulemakings and expected legal challenges. Changes in the U.S. presidential administration following the 2024 presidential election could also affect the implementation of the NSPS Subpart OOOOb and OOOOc rules See also “—Regulation of GHG Emissions.”

Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase REPX’s costs of development, which costs could be significant. States may also impose more stringent air permitting and air quality requirements than federal requirements. For example, in March 2021, the NMOCD finalized rules to eliminate venting and flaring at new and existing wells, and requiring operators to capture at least 98% of natural gas produced from their wells by 2026. In addition, the New Mexico Environment Department adopted a rule in August 2022 that requires oil and natural gas producers in counties that are at risk of non-attainment of federal ozone standards to, among other things, check emission rates and have those calculations certified by a qualified engineer, perform enhanced checks for leaks, and repair them within 15 days of discovery, and maintain records to demonstrate continuous compliance.

Regulation of GHG Emissions

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 pursuant to the federal CAA that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet “best available control technology” standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect REPX’s operations and restrict or delay REPX’s ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of REPX’s operations. More recently, in August 2022, Congress passed the Inflation Reduction Act (“IRA”), which includes requirements to impose fees beginning in 2025 on methane emissions from oil and gas operations that are required to report their GHG emissions under the EPA’s GHG Reporting Rule. EPA’s proposed rule to implement the fee requirements, “Waste Emissions Charge for Petroleum and Natural Gas Systems,” was published on January 26, 2024, with comments due by March 11, 2024. Furthermore, as discussed under "Air Emissions," in May 2016, the EPA finalized the NSPS Subpart OOOOa standards for emissions of VOC's and methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. Although limiting VOC emissions has the co-benefit of also limiting methane emissions, and previous iterations of the NSPS Subpart OOOO program limited VOC emissions from these sources, the Subpart OOOOa rules included first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rules impose leak detection and repair requirements intended to address emissions leaks known as “fugitive emissions” from equipment, such as valves, connectors, open ended lines, pressure-relief devices, compressors, instruments and meters. Although much of the initial rules remain intact and effective, the rules have been subject to legal challenges, reconsideration by the EPA, stays, and proposed amendments. More recently, EPA proposed and has since announced final rules to be codified as NSPS Subparts OOOOb and OOOOc that expand the OOOO regulatory program. For example, notably, the NSPS Subpart OOOOc rules include emissions guidelines to assist states in the development of plans to regulate methane emissions from certain existing sources, which had not previously been regulated under NSPS Subpart OOOO programs. Legal challenges to the recently announced final NSPS Subparts OOOOb and OOOOc rules are likely to follow, and thus, the ultimate scope of these regulations remains uncertain. Compliance with these rules requires enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance.

The BLM also finalized similar rules regarding the control of methane emissions in November 2016 that apply to oil and natural gas exploration and development activities on federal and Indian lands. The rules sought to minimize venting and flaring of emissions from storage tanks and other equipment, and also impose leak detection and repair requirements. However, due to subsequent BLM revisions and multiple legal challenges, the rules were never fully implemented, and in October 2020, the November 2016 rules were struck down by the District Court of Wyoming as the result of one such challenge. In part in response to the IRA requirement for operators to pay royalties on “all gas that is consumed or lost by venting, flaring, or negligent releases through any equipment during upstream operations,” the BLM has since proposed but not yet finalized the 2022 Waste Prevention Rule, which was published in the Federal Register on November 30, 2022, with comments due January 30, 2023, and is intended to replace the BLM’s existing venting and flaring requirements in its Notice to Lessees and Operators of Onshore Federal and Indian Oil and Gas Leases: Royalty or Compensation for Oil and Gas Lost (“NTL–4A”). These newly proposed rules could result in increased compliance costs on REPX’s operations on federal and Indian lands.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. REPX regularly uses hydraulic fracturing as part of its operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have asserted jurisdiction over certain aspects of the process. The EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also taken the following actions: issued final regulations under the federal CAA establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; although final rules have not yet been issued, proposed a rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and, in June 2016, published an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands, including requirements for chemical disclosure, wellbore integrity, and handling of flowback water. However, following years of litigation, the BLM rescinded the rule in December 2017. BLM’s repeal of the rule was challenged in court, and in March 2020, the Northern District of California issued a ruling in favor of the BLM. This ruling was appealed, but the case has been administratively closed since November 15, 2021. In addition, in May 2022, the U.S. Government Accountability Office released a study on methane emissions from oil and gas development, which included a recommendation that the BLM consider whether to require gas capture plans, including gas capture targets, from operators on federal lands. The reinstatement of the BLM hydraulic fracturing regulations or the promulgation of BLM gas capture regulations may result in additional levels or regulation or complexity that could lead to operational delays and increased operating and compliance costs that could make it more difficult and costly to perform hydraulic fracturing on federal and Indian lands.

Certain governmental reviews have recently been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level. More recently, the EPA initiated a study of Oil and Gas Extraction Wastewater Management in 2018 that the agency characterizes as a “holistic look” at how produced water is regulated and managed by the EPA, states, and tribes, and has sought input on these issues from other stakeholders such as academics, non-governmental organizations, and industry. A primary focus of the study is to evaluate whether federal regulations allowing for more discharge options would be beneficial, for example, in addressing areas with concerns over scarcity of water and/or injection options. The EPA released a draft of the study in May 2019 and sought public input until July 1, 2019. The EPA's final report was issued in May 2020, which found mixed support from stakeholders regarding additional produced water discharge options. The EPA is still determining what, if any, next steps are appropriate regarding produced water management in light of the report. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA, CWA or other regulatory mechanisms.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. The EPA, however, has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the SDWA. The EPA has issued permitting guidance for oil and natural gas hydraulic fracturing activities using diesel fuels. Under the guidance, EPA defined the term "diesel" to include five categories of oils, including some such as kerosene, that are not traditionally considered to be diesel. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect REPX's operations.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the RRC issued a "well integrity rule," which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. In addition, New Mexico and Texas require oil and gas operators to disclose the chemicals utilized in hydraulic fracturing on the Frac Focus website. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular.

Compliance with existing related laws has not to date had a material adverse effect on REPX's operations or financial position, but if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where REPX operates, REPX could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities, and perhaps even be precluded from drilling wells.

Protected Species

The Endangered Species Act ("ESA") and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species or that species' habitat. REPX may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service ("UFWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act and the Bald and Golden Eagle Protection Act. In the past, the federal government has issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. While the Department of the Interior under the Trump administration determined that such "incidental takes" of migratory birds do not violate the Act, this position was overruled by a federal district court in New York in August 2020. Nevertheless, on January 7, 2021, the Department of the Interior issued a rule which excluded incidental takes from the definition of prohibited activities under the Act. This rule was short-lived, however, and in October 2021, the Department of the Interior issued a rule to reverse the agency's position on incidental takes. The reversal took effect on December 3, 2021. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause REPX to incur increased costs arising from species protection measures or could result in limitations on REPX's development activities that could have an adverse impact on REPX's ability to develop and produce reserves. If REPX were to have a portion of its leases designated as critical or suitable habitat, it could also adversely impact the value of REPX's leases.

OSHA, Emergency Response and Community Right-to-Know, and Risk Management Planning

REPX is subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state statutes whose purpose 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, the general duty clause and Risk Management Planning regulations promulgated under section 112(r) of the CAA and comparable state statutes and any implementing regulations require that REPX organizes and/or discloses information about hazardous materials used or produced in REPX's operations and that this information be provided to employees, state and local governmental authorities and citizens. These laws also require the development of risk management plans for certain facilities to prevent accidental releases of extremely hazardous substances and to minimize the consequences of such releases should they occur.

Related Permits and Authorizations

Many environmental laws require REPX to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for ongoing operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Related Insurance

REPX maintains insurance against some risks associated with aboveground, surface, or underground contamination that may occur as a result of REPX's exploration and production activities. However, this insurance is at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by REPX. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on REPX's financial condition and operations.

Facilities

Our land-based oil and natural gas processing facilities are typical of those found in the Permian Basin. Our facilities located at well locations or centralized lease locations include SWDs and associated gathering lines, storage tank batteries, oil/gas/water separation equipment and pumping equipment. In addition, we own a substantial majority of the electrical power infrastructure on our acreage position, which includes power distribution lines and equipment.

Human Capital

As of December 31, 2023, we employed 90 people. We operate in a technical industry and depend on a highly skilled workforce in multiple disciplines including engineering, geology, operations, land, information technology, accounting and various other corporate functions. The Company supports its employees in pursuing training opportunities to enhance their professional skills. We are not a party to any collective bargaining agreements with our employees. We understand that employee recruiting, retention and development plays a critical role to our business activities and our ability to achieve our long-term strategy. We believe our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Compensation and Benefits Program

The Company annually reviews compensation for all employees to adjust compensation for market conditions and attract and retain a highly skilled workforce. In addition to cash and equity compensation, the Company also offers other employee benefits such as life and health (medical, dental and vision) insurance, paid time off, and a 401(k) plan.

Diversity and Inclusion

We believe that diversity of backgrounds, experience and perspectives contributes to an innovative workforce and an enriching environment for our employees. We are committed to fostering an inclusive, respectful environment and providing equal opportunity to all qualified persons in our hiring, development, and compensation practices.

Community Involvement

The Company is dedicated to being a good neighbor in its operating areas. The Company provides support through various events, organizations, initiatives and partnerships.

Health, Safety and Environment

Protecting our employees, contractors, the public and the environment is a key focus for Riley Permian. The Company maintains a culture of continuous improvement in safety and environmental practices, supports a diverse workforce and inspires teamwork to drive innovation. We identify and mitigate safety risks and integrate a culture of safety by operating according to OSHA standards, processes, and procedures. We also strive to comply with all applicable health, safety and environmental standards, laws and regulations.

Corporate Information

We were formed as a Delaware limited liability company, Riley Exploration – Permian, LLC ("REP LLC"), in 2016. In February 2021, REP LLC consummated a merger pursuant to which REP LLC became a wholly-owned subsidiary of Tengasco, Inc., a Delaware corporation (“Tengasco”), and Tengasco changed its name to Riley Exploration Permian, Inc. (the "Merger"). Our organizational structure includes wholly-owned consolidated subsidiaries through which our operations are conducted, including without limitation, REP LLC and Riley Permian Operating Company, LLC. Our corporate headquarters are located at 29 E. Reno Avenue, Suite 500, Oklahoma City, Oklahoma 73104, and the phone number at this address is (405) 415-8699.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available free of charge on our website, www.rileypermian.com, as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this Annual Report or any other report that we file with or furnish to the SEC.

Item 1A. Risk Factors

The Company is subject to various risks and uncer tainties in the ordinary course of business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition or results of operations. Other risks are described in Item 1 and 2. Business and Properties, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 7A. Quantitative and Qualitative Disclosures About Market Risk. We could also face additional risks and uncertainties not currently known to us or that we currently deem to be immaterial. If any of these risks actually occurs, it could materially harm our business, financial condition or results of operations and the trading price of our shares could decline. Investors should carefully consider each of the following risk factors and all of the other information set forth in this Annual Report.

Risks Related to our Business, Operations, and Strategy

Recent regulatory restrictions on use of produced water and a moratorium on new produced water disposal wells in certain areas of the Permian Basin to stem rising seismic activity and earthquakes could increase our operating costs and adversely impact our business, results of operations and financial condition.

The NMOCD and the RRC have each imposed stricter requirements for oil and gas wastewater injection activities in response to seismic activity in the Permian Basin. For example, in November 2021, NMOCD implemented a “Seismicity Response Protocol” that imposes additional analysis, reporting, injection rate reduction or curtailment, and notification requirements on operators depending on the number and intensity of seismic events. 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. In October 2021, the RRC identified an additional SRA—the Northern Culberson-Reeves (“NCR”) SRA—and, in January 2022, the RRC identified still another SRA—the Stanton SRA. Operators in the NCR and Stanton SRAs were required to implement seismic response plans, which include expanded data collection efforts, contingency responses for future seismicity, and scheduled checkpoint updates with RRC staff. Both the Gardendale and NCR SRAs were expanded in December 2022 in response to additional earthquakes in the area and, effective January 12, 2024, the RRC suspended all (totaling 23) deep disposal well permits in the NCR SRA. These actions were taken in an effort to control induced seismic activity and recent increases in earthquakes in the Permian Basin, which have been linked by the U.S. and local seismologists to wastewater disposal in oil fields. These restrictions on the disposal of produced water and a moratorium on new produced water disposal wells could result in increased operating costs, requiring us or our service providers to truck produced water, recycle it or dispose of it by other means, all of which could be costly. We or our service providers may also need to limit disposal well volumes, disposal rates and pressures or locations, or require us or our service providers to shut down or curtail the injection of produced water into disposal wells. These factors may make drilling activity in the affected parts of the Permian Basin less economical and adversely impact our business, results of operations and financial condition.

Enhanced scrutiny on ESG matters could have an adverse effect on the Company's operations.

Enhanced scrutiny on ESG matters related to, among other things, concerns raised by advocacy groups about climate change, hydraulic fracturing, natural gas flaring, GHG emissions, waste disposal, oil spills, and explosions of natural gas transmission pipelines may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines, and enforcement interpretations. These concerns and actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens, increased risk of litigation, and adverse impacts on the Company's access to capital. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance, and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits the Company requires to conduct its operations to be withheld, delayed, or burdened by requirements that restrict the Company's ability to profitably conduct its business.

We may be unable to quickly adapt to changes in market/investor priorities.

Historically, one of the key drivers in the unconventional resource industry has been growth in production and reserves. With historical volatility in oil and natural gas prices and the likelihood that rising interest rates will increase the cost of borrowing, capital efficiency and free cash flow from earnings have become the key drivers for energy companies, particularly shale producers. Such shifts in focus sometimes require changes in planning and resource management, which may not occur instantaneously. Any delay in responding to such changes in market sentiment or perception may result in the investment community having a negative sentiment regarding our business plan, potential profitability and our ability to operate in a manner deemed "efficient," which may have a negative impact on the price of our common stock.

Oil, natural gas, and NGL prices are volatile. An extended decline in commodity prices may adversely affect our business, financial condition, or results of operations and our ability to meet our capital expenditure obligations and financial commitments. Additionally, the value of our reserves calculated using SEC pricing may be higher than the fair market value of our reserves calculated using current market prices.

The prices we receive for our oil, natural gas, and NGL production heavily influence our revenue, profitability, access to capital, and future rate of growth. Oil, natural gas, and NGLs are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. For example, during the period from January 1, 2016 to December 31, 2023, NYMEX West Texas Intermediate (referred to as WTI) oil prices ranged from a high of $123.64 per Bbl on March 8, 2022 to a low of $(36.98) per Bbl on April 20, 2020. During 2023, WTI prices ranged from a high of $93.67 to a low of $66.61 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $3.78 per MMBtu to a low of $1.74 per MMBtu during 2023. If the prices of oil and natural gas continue to be volatile, reverse their recent increases, or decline, our operations, financial condition, cash flows and level of expenditures may be materially and adversely affected. Moreover, the duration and magnitude of any decline in oil, natural gas or NGL prices cannot be predicted with accuracy, and this market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas, and NGLs;
- private and government investment in and regulatory incentives for non-fossil fuel energy production;
- changes in applicable laws and regulations;
- the price and quantity of foreign imports, including foreign oil;
- the actions by members of OPEC+;
- political, economic, and military conditions in or affecting other producing countries, including embargoes or conflicts in the Middle East, Africa, South America and Russia;
- the level of global oil and natural gas exploration and production activity;

- the level of global oil and natural gas inventories;
- prevailing prices on local price indices in the areas in which we operate;
- the cost of producing and delivering oil and natural gas and conducting other operations;
- the recovery rates of new oil, natural gas and NGL reserves;
- lead times associated with acquiring equipment and products, and availability of qualified personnel;
- late deliveries of supplies;
- technical difficulties or failures;
- the proximity, capacity, cost, and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- localized and global weather conditions and events;
- public health concerns such as pandemic diseases;
- technological advances affecting energy consumption, including advances in exploration, development and production technologies;
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development and production of oil, natural gas, and NGLs;
- uncertainty in capital and commodities markets and the ability of companies in our industry to raise equity capital and debt financing;
- the price and availability of alternative fuels; and
- domestic, local, and foreign governmental regulation and taxes.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil, natural gas and NGLs that we can produce economically. We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements may be limited, and, in the future, we will not be under an obligation to hedge a specific portion of our oil or natural gas production.

Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits. While it is difficult to project future economic conditions and whether such conditions will result in impairment of proved property costs, we consider several variables including specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors. In addition, sustained periods with oil and natural gas prices at levels lower than current West Texas Intermediate strip prices and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves and related standardized measure. If we are required to curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity, or ability to finance planned capital expenditures.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write down constitutes a non-cash charge to earnings. If market or other economic conditions deteriorate or if oil, natural gas and NGL prices decline, we may incur impairment charges, which may have a material adverse effect on our results of operations.

During the year ended December 31, 2023, the Company recognized an impairment loss on proved properties relating to certain properties in Texas outside of the Company's acreage in the Champions Field. The impairment was primarily driven by notably lower commodity pricing at the time of measurement of fair value at year-end 2023.

Our exploration and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development, and acquisition of oil and natural gas reserves. We expect to fund our growth primarily through cash flow from operations, availability under our Credit Facility, and subsequent equity or debt offerings when appropriate. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices, actual drilling results, the availability of drilling rigs and other services and equipment, regulatory, technological and competitive developments, and worldwide and regional economic conditions. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells and the timing of such production;
- the prices at which our production is sold;
- operating costs and other expenses;
- the availability of takeaway capacity;
- Credit Facility and/or investor requirements;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our Credit Facility.

If our revenue or the borrowing base under our Credit Facility decreases as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations and growth at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our Credit Facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and would adversely affect our business, financial condition, and results of operations.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We have acquired unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot provide assurance that all prospects will be economically viable or that we will not abandon our undeveloped acreage. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive, or that we will recover all or any portion of our investment in such unproved property or wells.

Properties that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

Our prospects are in various stages of evaluation, ranging from prospects that are currently being drilled, to prospects that will require substantial additional seismic data processing and interpretation. Properties that we decide to drill that do not yield oil, natural gas or NGLs in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;

- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire, or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs, and potential liabilities, including environmental liabilities. Such assessments are inexact, inherently uncertain, and often time-constrained. For these reasons, the properties we have acquired or will acquire in the future may not produce as projected or may be more costly to operate than projected. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not review every well, pipeline or associated facility. We cannot necessarily observe structural and environmental problems, such as pipe corrosion or groundwater contamination, when a review is performed. We may be unable to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical and environmental condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves.

In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes, and availability of funds.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may revise reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

The present value of future net revenues from our reserves should not be assumed to represent the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. For example, our estimated proved reserves as of December 31, 2023 were calculated under SEC rules using the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months of $78.22 per Bbl for oil and NGL volumes and $2.64 per MMBtu for natural gas volumes. Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits.

There is a limited amount of production data from horizontal wells completed in the Permian Basin and its San Andres Formation. As a result, reserve estimates associated with horizontal wells in this area are subject to greater uncertainty than estimates associated with reserves attributable to vertical wells in the same area.

Reserve engineers rely in part on the production history of nearby wells in establishing reserve estimates for a particular well or field. Horizontal drilling in the San Andres Formation of the Permian Basin is a relatively recent development, whereas vertical drilling has been utilized by producers in this area for over 50 years. As a result, the amount of production data from horizontal wells available to reserve engineers is relatively small compared to that of production data from vertical wells. Until a greater number of horizontal wells have been completed in the San Andres Formation, and a longer production history from these wells has been established, there may be a greater variance in our proved reserves on a year-over-year basis due to the transition from vertical to horizontal reserves in both the proved developed and proved undeveloped categories. Such variance could be material and any such variance could have a material and adverse impact on our cash flows and results of operations.

Part of our strategy involves drilling using the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. As of December 31, 2023, we had drilled and completed 517 gross operated horizontal wells on our West Texas and New Mexico acreage, and therefore are subject to increased risks associated with horizontal drilling as compared to companies that have greater experience in horizontal drilling activities. Risks that we face while drilling include, but are not limited to, failing to land our wellbore in the desired drilling zone, not staying in the desired drilling zone while drilling horizontally through the formation, not running our casing the entire length of the wellbore and not being able to run tools and other equipment consistently through the horizontal wellbore. Risks that we face while completing our wells include, but are not limited to, not being able to fracture stimulate the planned number of stages, not being able to run tools the entire length of the wellbore during completion operations and not successfully cleaning out the wellbore after completion of the final fracture stimulation stage.

Additionally, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficient time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or commodity prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Approximately 6% of our net leasehold acreage is undeveloped and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Oil and natural gas leases generally must be drilled before the end of the lease term or the leaseholder will lose the lease and any capital invested therein. In addition, leases may also be lost due to legal issues relating to the ownership of leases. Any delays in drilling or legal issues causing us to lose leases on properties could have a material adverse effect on our results of operations and reserve growth.

As of December 31, 2023, approximately 6% of our net leasehold acreage was undeveloped or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. Unless production is established on the undeveloped acreage covered by our leases, such leases will expire. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our drilling plans are subject to change based upon various factors, including factors that are beyond our control. Such factors include drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. If our leases expire, we will lose our right to develop such properties.

Substantially all of our producing properties are located in the Northwest Shelf within the Permian Basin of West Texas and Southeastern New Mexico, making us vulnerable to risks associated with operating in one major geographic area. Specifically, as the Permian Basin is an area of high industry activity, we may be unable to hire, train, or retain qualified personnel needed to manage and operate our assets.

At December 31, 2023, the majority of our total estimated proved reserves were attributable to properties located in the Northwest Shelf within the Permian Basin of West Texas and Southeastern New Mexico, an area in which industry activity has increased rapidly. As a result of this concentration, a number of our properties could experience any of the same conditions at the same time and, when compared to other companies that have a more diversified portfolio of properties, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints or disruptions, market limitations, water shortages or other drought or extreme weather related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

Specifically, demand for qualified personnel in this area, and the cost to attract and retain such personnel, may increase substantially in the future. Moreover, our competitors, including those operating in multiple basins, may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could have a negative effect on production volumes or significantly increase costs, which could have a material adverse effect on our results of operations, liquidity and financial condition.

In addition, the geographic concentration of our assets, including our total estim ated proved reserves as of December 31, 2023, exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and natural gas production, certain of which we do not control, and our initiatives to expand our access to midstream and operational infrastructure may be unsuccessful.

The marketing of oil and natural gas production depends in large part on the capacity and availability of pipelines and storage facilities, trucks, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If these facilities are unavailable to us on commercially reasonable terms or otherwise (either temporarily or long-term), we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons, as was the case in July and August 2023 when our producing wells in the Redlake field in New Mexico were shut in due to an unexpected maintenance issue with our third party processing plant. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit, and sell our oil and natural gas production. Our plans to develop and sell our oil and natural gas reserves, the expected results of our drilling program and our cash flow and results of operations could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil and natural gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. For example, increases in activity in the Permian Basin could contribute to bottlenecks in processing and transportation that may negatively affect our results of operations, and these adverse effects could be disproportionately severe to us compared to our more geographically diverse competitors.

Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules, which could adversely affect development activities or production relating to those formations. In addition, in areas where exploration and production activities are increasing, as has been the case in recent years in the Permian Basin, we are subject to increasing competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages or delays. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

While we have undertaken initiatives to expand our access to midstream and operational infrastructure, these initiatives may be delayed or unsuccessful. As a result, our business, financial condition, and results of operations could be adversely affected.

The prices we receive for our production may be affected by local and regional factors.

The prices we receive for our production will be determined to a significant extent by factors affecting the local and regional supply of and demand for oil and natural gas, including the adequacy of the pipeline and processing infrastructure in the region to process and transport our production and that of other producers. Those factors result in basis differentials between the published indices generally used to establish the price received for regional oil and natural gas production and the actual price we receive for our production, which may be lower than index prices. If the price differentials pursuant to which our production is subject were to widen due to oversupply or other factors, our revenue could be negatively impacted.

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

Our oil and natural gas is priced in the local markets where it is produced based on local or regional supply and demand factors. The prices we receive for our oil and natural gas are typically lower than the relevant benchmark prices, such as NYMEX WTI. The difference between the benchmark price and the price we receive is called a differential. Numerous factors may influence local pricing, such as pipeline capacity and processing infrastructure. Additionally, insufficient pipeline or transportation capacity, lack of demand in any given operating area or other factors may cause the differential to increase in a particular area compared with other producing areas. For example, production increases from competing Permian Basin producers, combined with limited pipeline and transportation capacity in the area, have gradually widened differentials in the Permian Basin.

For the year ended December 31, 2023, our realized oil differential to NYMEX WTI averaged $(1.96) per Bbl of oil and our realized natural gas differential to NYMEX Henry Hub averaged $(2.08) per Mcf of gas. Given that a significant amount of our production is from the Permian Basin, if the negative price differential in the Permian Basin increases, we expect that the effect of our price differential on our revenues will also increase. Increases in the differential between the benchmark prices for oil and natural gas, such as the NYMEX WTI and NYMEX Henry Hub, and the realized price we receive could significantly reduce our revenues and our cash flow from operations.

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

At December 31, 2023, approximately 44% of our total estimated proved reserves were classified as proved undeveloped. Our approximate 47,537 MBoe of estimated proved undeveloped reserves are estimated to require $322.7 million of development capital. Our development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. We expect to fund our growth primarily through cash flow from operations, availability under our Credit Facility, and subsequent equity or debt offerings when appropriate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

We participate in oil and natural gas leases with third parties who may not be able to fulfill their commitments to our projects.

We own less than 100% of the working interest in the oil and natural gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, may be unable to access debt or equity financing, and, in some cases, may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

We own non-operating interests in properties developed and operated by third parties and, as a result, we are unable to control the operation and profitability of such properties.

We participate in the drilling and completion of wells with third-party operators that exercise exclusive control over such operations. As a participant, we rely on the third-party operators to successfully operate these properties pursuant to joint operating agreements and other similar contractual arrangements.

As a participant in these operations, we may not be able to maximize the value associated with these properties in the manner we believe appropriate, or at all. For example, we cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third-party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third-party operator's operational expertise and financial resources and its ability to gain the approval of other participants in drilling wells will impact the timing and potential success of drilling and development activities in a manner that we are unable to control. A third-party operator's failure to adequately perform operations, breach of the applicable agreements or failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil, natural gas and NGLs we produce.

The availability of a ready market for any oil, natural gas and NGLs we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of oil and gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production.

We have exposure to credit risk through receivables from purchasers of our oil, natural gas and NGL production. One purchaser accounted for 70% of our revenues and another purchaser accounted for more than 10% of our revenues for the year ended December 31, 2023. This concentration of purchasers may impact our overall credit risk in that these purchasers may be similarly affected by changes in economic conditions or commodity price fluctuations. We do not require our customers to post collateral. The inability or failure of our significant purchasers to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial condition and results of operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

Our operations are subject to inherent risks, some of which are beyond our control. We are not insured against all risks. Losses and liabilities arising from uninsured and under insured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering or other cratering, uncontrollable flows of natural gas, oil, well fluids and formation water, pipe or pipeline failures, processing or transportation capacity constraints or disruptions, abnormally pressured formations, casing collapses, reservoir damage and environmental hazards such as oil, produced water or chemical spills, natural gas leaks, ruptures or discharges of toxic gases.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- medical monitoring;
- natural resources damages;
- employee/employer liabilities and risks, including wrongful termination, discrimination, labor organizing, retaliation claims, and general human resource related matters;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental hazards or damage;
- abnormally pressured formations, fires or explosions or natural disasters;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- regulatory investigations and penalties;
- landowner claims for property damage and restoration costs;
- suspension of our operations;
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. Claims for loss of oil and natural gas production and damage to formations can occur in our industry. Litigation arising from a catastrophic occurrence at a location where our systems are deployed may result in our being named as a defendant in lawsuits asserting large claims.

Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Also, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or fully covered by insurance and any delay in the payment of insurance proceeds for covered events could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to make accretive acquisitions or successfully integrate acquired businesses or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of oil and natural gas properties or businesses that complement or expand our current business. The successful acquisition of oil and natural gas properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil, natural gas and NGL prices and their applicable differentials;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- environmental and other liabilities.

The accuracy of these assessments is inherently uncertain, and we may not be able to identify accretive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Reviews may not always be performed on every well or facility, and environmental problems, such as subsurface or groundwater contamination, are not necessarily observable even when a review is performed. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an “as is” basis. Even if we do identify accretive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our Credit Facility imposes certain limitations on our ability to enter into mergers or combination transactions as well as limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of lease brokers or land men who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

Our operations could be impacted by burdens and encumbrances on title to our properties.

Our leasehold and other acreage may be subject to existing oil and natural gas leases, liens for current taxes and other burdens, including other mineral encumbrances and restrictions customary in the oil and natural gas industry. Such liens and burdens could materially interfere with the use or otherwise affect the value of such properties. Additionally, any cloud on the title of the working interests, leases and other rights owned by us could have a material adverse effect on our operations.

Our undeveloped acreage must be drilled before lease expirations to hold the acreage by production or by other operations. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, our leases for such acreage will expire. As of December 31, 2023, 43% of our net undeveloped acreage is set to expire in 2024, before taking into account the expected drilling of wells and holding leases by production, while 4% of our net undeveloped acreage is set to expire through 2024, after taking into account the expected drilling of wells and holding leases by production. We intend to extend or renew any core lease we plan to develop or are still assessing for development that is set to expire in 2024 and expect to incur $0.2 million to extend or renew those leases, after taking into account the expected drilling of wells and holding leases by production. Where we do not have the option to extend a lease, however, we may not be successful in negotiating extensions or renewals. Our ability to drill and develop our core acreage and establish production to maintain our leases depends on a number of uncertainties, including oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business. These risks are greater at times and in areas where the pace of our exploration and development activity slows.

We plan to use CO_2 for our EOR projects. Our production from these EOR operations may decline if we are not able to obtain sufficient amounts of CO_2.

Oil production from our EOR projects depends on, among other factors, having access to sufficient amounts of CO_2 from our third-party suppliers of CO_2. Our ability to produce oil from our EOR projects would be hindered if the supply of CO_2 was limited due to, among other things, physical limitations on CO_2 supply or the ability to economically procure CO_2 at costs low enough to ensure the economic viability of our EOR projects. This could have a material adverse effect on our financial condition, results of operations or cash flows. Future oil production from the Company's EOR projects is dependent on the timing, volumes and location of CO_2 injections and, in particular, our ability to obtain sufficient volumes of CO_2. Market conditions may cause the delay or cancellation of the development of naturally occurring CO_2 sources or construction of plants that produce anthropogenic CO_2 as a byproduct that can be purchased, thus limiting the amount of CO_2 available for use in our EOR projects.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

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 properties will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. Also, our reviews of acquired properties are inherently incomplete because it generally is not economically feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections are often not performed on properties being acquired, and environmental matters, such as subsurface and groundwater 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;
- dilution to stockholders if we use equity as consideration for, or to finance, acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- 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.

Our future results will suffer if we do not effectively manage our expanded operations.

As a result of our recent acquisitions, the size and geographic footprint of our business has increased. Our future success will depend, in part, upon our ability to manage this 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 the increase 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 recent and future acquisitions.

Acquisitions of assets or businesses may reduce, rather than increase, our distributable cash flow or may disrupt our business.

Even if we make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in our cash flow. Any acquisition involves potential risks that may disrupt our business, including the following, among other things:

- mistaken assumptions about volumes or the timing of those volumes, revenues or costs, including synergies;
- an inability to successfully integrate the acquired assets or businesses;

- the assumption of unknown liabilities;
- exposure to potential lawsuits;
- limitations on rights to indemnity from the seller;
- the diversion of management’s and employees’ attention from other business concerns;
- unforeseen difficulties operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

We may need to access funding through capital market transactions. Due to our small public float, low market capitalization, limited operating history, ESG, and climate change restrictions, it may be difficult and expensive for us to raise additional funds.

We may need to raise funds through the issuance of shares of our common stock or securities linked to our common stock. Our ability to raise these funds may be dependent on a number of factors, including the risk factors further described herein and the low trading volume and volatile trading price of our shares of common stock. The stocks of small cap companies tend to be highly volatile. We expect that the price of our common stock will be highly volatile for the next several years.

As a result, we may be unable to access funding through sales of our common stock or other equity-linked securities. Even if we were able to access funding, the cost of capital may be substantial due to our low market cap and small public float. The terms of any funding we are able to obtain may not be favorable to us and may be highly dilutive to our stockholders. We may be unable to access capital due to unfavorable market conditions or other market factors outside of our control such as ESG and/or climate change policies and restrictions. There can be no assurance that we will be able to raise additional capital when needed. The failure to obtain additional capital when needed would have a material adverse effect on our business.

Our Credit Facility and our Senior Notes have substantial restrictions and financial covenants that may restrict our business and financing activities and our ability to declare dividends.

The operating and financial restrictions and covenants in our Credit Facility and our Senior Notes restrict, and any future financing agreements likely will restrict, our ability to finance future operations or capital needs, engage, expand or pursue our business activities or pay dividends. Our Credit Facility and our Senior Notes restrict, and any future financing agreements likely will restrict, our ability to, among other things:

- incur indebtedness;
- issue certain equity securities, including preferred equity securities;
- incur certain liens or permit them to exist;
- engage in certain fundamental changes, including mergers or consolidations;
- make certain investments, loans, advances, guarantees and acquisitions;
- sell or transfer assets;
- enter into sale and leaseback transactions;
- redeem or repurchase shares from our stockholders;
- pay dividends to our stockholders unless certain tests under the Credit Facility and Senior Notes are satisfied;
- make certain payments of junior indebtedness;
- enter into certain types of transactions with our affiliates;
- enter into certain restrictive agreements;
- make certain amendments to our governing documents;
- make certain accounting changes; and
- enter into swap agreements and hedging arrangements.

Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of free cash flow and events or circumstances beyond our control, such as a downturn in our business or the economy in general or reduced oil, natural gas and NGL prices. A failure to comply with the provisions of our Credit Facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. Further, our ability to pay dividends to our stockholders will be restricted and our lenders’ commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments, and our common stockholders could experience a partial or total loss of their investment. In addition, our obligations under our Credit Facility are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our Credit Facility, the lenders can seek to foreclose on our assets.

Our indebtedness could reduce our financial flexibility.

The level of our indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flow could be used to service the indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in our Credit Facility and Senior Notes limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments; and
- a high level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate purposes, or other purposes.

Any significant reduction in our borrowing base under our Credit Facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our Credit Facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine in accordance with the terms of the agreement. The borrowing base depends on, among other things, projected revenues from, and asset values of, the proved oil and natural gas properties securing our loan. The value of our proved reserves is dependent upon, among other things, the prevailing and expected market prices of the underlying commodities in our estimated reserves. A further reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations, and our ability to meet our capital expenditure obligations and financial commitments. Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. We could be forced to repay a portion of our bank borrowings or transfer to the lenders additional collateral due to redeterminations of our borrowing base that result in a reduction of the available revolving commitments. If we are forced to do so, we may not have sufficient funds to make such repayments or provide such collateral. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings, provide additional collateral 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.

In the future, we may not be able to access adequate funding under our Credit Facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a redetermination and reduction of the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the reduced borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our debt arrangements, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital, or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of our existing Credit Facility, our Senior Notes, or future debt arrangements may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our Credit Facility and our Senior Notes currently restrict our ability to dispose of assets and our use of the proceeds from such dispositions. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

Our derivative activities could result in financial losses or could reduce our earnings.

We enter or may enter into commodity derivative contracts for a portion of our production, primarily consisting of swaps, put options and call options. We purchase such derivatives to achieve more predictable cash flows, to reduce our exposure to adverse fluctuations in the prices of oil, natural gas, and NGLs, and in order to remain in compliance with covenants in our Credit Facility. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also can expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced, which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil, natural gas, and NGL prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil, natural gas, and NGLs, which could also have an adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty’s liquidity, which could make them unable to perform under the terms of the contract and we may not be able to realize the benefit of the contract. We are unable to predict sudden changes in a counterparty’s creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our derivative contract receivable positions could generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss with respect to our commodity derivative contracts.

Risks Related to the Oil and Natural Gas Industry

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

Our future financial condition and results of operations will depend on the success of our exploitation, development, and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production.

Our decisions to purchase, explore, develop, or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data, and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.” In addition, our cost of drilling, completing, and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay, or cancel our scheduled drilling projects, including the following:

- delays and increased costs imposed by or resulting from compliance with environmental and other regulatory requirements including limitations on or resulting from wastewater discharge and disposal, subsurface injections, greenhouse gas emissions, and hydraulic fracturing;
- pressure or irregularities in geological formations;

- increases in the cost of, or shortages or delays in availability of drilling rigs and qualified personnel for hydraulic fracturing activities;
- shortages of or delays in obtaining water resources, suitable proppant, and chemicals in sufficient quantities for use in hydraulic fracturing activities;
- equipment failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity or disruptions in operation of interconnecting transmission pipelines and processing facilities;
- adverse weather conditions, such as tornadoes, droughts, ice storms, and extreme freeze events;
- lack of available treatment or disposal options for oil and natural gas waste, including produced water;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the air, surface and subsurface environment;
- issues related to permitting under and compliance with environmental and other governmental regulations;
- declines or volatility in oil, natural gas, and NGL prices;
- limited availability of financing at acceptable terms;
- title problems or legal disputes regarding leasehold rights; and
- limitations in the market for oil, natural gas, and NGLs.

Conservation measures and technological advances could reduce demand for oil, natural gas and NGLs.

Our industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. Fuel and other energy conservation measures, alternative fuel requirements, prioritization of advancements in renewable energy production, increasing consumer demand for alternatives to oil, natural gas and NGLs, and technological advances in fuel economy and energy generation devices could reduce demand for oil, natural gas and NGLs. As competitors and others use or develop new technologies or technologies comparable to ours in the future, we may lose market share or be placed at a competitive disadvantage. Further, we may face competitive pressure to implement or acquire certain new technologies at a substantial cost. Some of our competitors may have greater financial, technical and personnel resources than we do, which may allow them to gain technological advantages or implement new technologies before we can. Additionally, we may be unable to implement new technologies or services at all, on a timely basis or at an acceptable cost. Limits on our ability to effectively use, implement or adapt to new technologies may have a material adverse effect on our business, financial condition and results of operations. Similarly, the impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Limitation or restrictions on our ability to obtain water or dispose of flowback and produced water may have an adverse effect on our operating results.

Water is an essential component of shale and conventional oil and natural gas development during both the drilling and hydraulic fracturing processes. Our access to water to be used in these processes may be adversely affected due to reasons such as periods of extended drought, private, third-party competition for water in localized areas or the implementation of local or state governmental programs to monitor or restrict the use of water subject to their jurisdiction for hydraulic fracturing to assure adequate local water supplies. In addition, treatment and disposal of flowback and produced water is becoming more highly regulated and restricted, including, in some areas, due to seismic activity associated with saltwater disposal wells. Thus, our costs for obtaining and disposing of water could increase significantly. Our inability to locate or contractually acquire and sustain the receipt of sufficient amounts of water could adversely impact our exploration and production operations and have a corresponding adverse effect on our business, results of operations and financial condition.

The unavailability or high cost of equipment, supplies, personnel and oilfield services used to drill and complete wells could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Our operations are concentrated in areas in which activity has increased rapidly, and as a result, demand for such drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities in these areas, has increased, as have the costs for those items. In addition, to the extent our suppliers source their products or raw materials from foreign markets, the cost of such equipment could be impacted if the United States imposes tariffs on imported goods from countries where these goods are produced. Such shortages or cost increases could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties and market oil or natural gas.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, and raising additional capital, which could have a material adverse effect on our business.

Declining general economic, business or industry conditions have, and will continue to have, a material adverse effect on our results of operations, liquidity and financial condition, and are expected to continue having a material adverse effect for the foreseeable future.

Concerns over global economic conditions, the threat of pandemic diseases and the results thereof, energy costs, geopolitical issues, inflation, the availability and cost of credit have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil and natural gas, declining business and consumer confidence, and increased unemployment, have precipitated an economic slowdown and a recession, which could expand to a global depression. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices and are expected to continue having a material adverse effect for the foreseeable future. For example, it is uncertain how conflicts in the Middle East, including the war in Gaza, and the war in Ukraine and resulting sanctions against Russia will affect oil and natural gas prices in the coming months. If the economic climate in the United States or abroad continues to deteriorate, demand for petroleum products could diminish, which could further impact the price at which our operators can sell oil, natural gas, and NGLs, affect the ability of our vendors, suppliers and customers to continue operations, and ultimately adversely impact our results of operations, liquidity and financial condition to a greater extent than it has already. In addition, a decline in consumer confidence or changing patterns in the availability and use of disposable income by consumers can negatively affect the demand for oil and natural gas as a result of our results of operations.

Continuing or worsening inflationary issues and associated changes in monetary policy have resulted in and may result in additional increases to the cost of our goods, services and personnel, which in turn cause our capital expenditures and operating costs to rise.

Inflation has been an ongoing concern in the U.S. since 2021. Ongoing inflationary pressures have resulted in and may result in additional increases to the costs of goods, services and personnel, which in turn cause our capital expenditures and operating costs to rise. Sustained levels of high inflation caused the U.S. Federal Reserve and other central banks to increase interest rates beginning in 2022 and continuing in 2023 in an effort to curb inflationary pressure on the costs of goods and services, which could have the effects of raising the cost of capital and depressing economic growth, either of which (or the combination thereof) could hurt the financial and operating results of our business. We may experience further cost increases for our operations to the extent that elevated inflation remains.

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

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies 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 can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, oil spills, seismic activity, greenhouse gas emissions, and explosions of natural gas transmission lines may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

Risks Related to Acts of God and Cybersecurity

Power outages, limited availability of electrical resources, and increased energy costs could have a material adverse effect on us.

Our operations are subject to electrical power outages, regional competition for available power, and increased energy costs. Power outages, which may last beyond our backup and alternative power arrangements, would harm our operations and our business.

We also may be subject to risks and unanticipated costs associated with obtaining power from various utility companies. Such utilities may be dependent on, and sensitive to price increases for, a particular type of fuel, such as coal, oil or natural gas. The price of these fuels and the electricity generated from them could increase as a result of proposed legislative measures related to climate change or efforts to regulate carbon or other greenhouse gas emissions.

Extreme weather conditions could adversely affect our ability to conduct drilling and production activities in the areas where we operate.

Our exploration, exploitation, development, and production activities and equipment could be adversely affected by extreme weather conditions, such as floods, lightening, 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. Such extreme weather conditions could also impact other areas of our operations, including access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of, and our access to, necessary third-party services, such as electrical power, water, gathering, processing, compression, transportation, and produced water disposal services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations. For example, the industry depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. As an oil and natural gas producer, our technologies, systems, networks, and those of our business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, misuse, loss or destruction of proprietary and other information, or other disruption of business operations that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. We 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 our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. 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 reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could lead to financial losses from remedial actions, loss of business or potential liability.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Related to Legal, Regulatory, and Tax Matters

We are subject to stringent federal, state and local laws and regulations related to environmental and occupational health and safety issues that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our operations are subject to stringent federal, state and local laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and environmental and human health and safety protection. These laws and regulations may impose numerous obligations applicable to our operations including (i) the acquisition of a permit before conducting drilling, production, and other regulated activities; (ii) the restriction of types, quantities and concentration of materials that may be released into the environment; (iii) the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, protected species habitat, and other sensitive or protected areas; (iv) the application of specific health and safety criteria addressing worker protection; (v) the imposition of substantial liabilities for pollution resulting from our operations; (vi) the installation of costly emission monitoring and/or pollution control equipment; and (vii) the reporting of the types and quantities of various substances that are generated, stored, processed, transported, disposed, or released in connection with our properties. Numerous governmental authorities, such as the EPA, the U.S. Fish and Wildlife Service, and analogous state agencies, such as the New Mexico Environment Department and the Texas Commission on Environmental Quality, and state oil and natural gas commissions, such as the New Mexico Oil Conservation Division and the Railroad Commission of Texas, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, the imposition of investigatory or remedial obligations, and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining or be unable to obtain required permits, which may delay or interrupt our operations or specific projects and limit our growth and revenue.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties, as well as locations where waste from our operations is transported offsite for disposal. Spills or other releases of regulated substances, including such spills and releases that occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted. We may not be able to recover some or any of these costs from insurance. Changes in environmental laws and regulations occur frequently and tend to become more stringent over time, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position or financial condition. For example, on October 1, 2015, the EPA issued a final rule under the CAA, lowering the NAAQS for ground-level ozone from the current standard of 75 parts per billion, or ppb, for the current 8-hour primary and secondary ozone standards to 70 ppb for both standards. Subsequently, the EPA designated over 200 counties across the U.S. as “nonattainment” for these standards, meaning that new and modified stationary emissions sources in these areas are subject to more stringent permitting and pollution control requirements. On December 23, 2021, the EPA announced its decision to retain, without changes, the 2015 NAAQS. On August 21, 2023, EPA announced the initiation of a new review of the ozone NAAQS to ensure the standards reflect the most current, relevant science. EPA’s review is ongoing. If our operations become subject to these more stringent standards, compliance with these and other environmental regulations could delay or prohibit our ability to obtain permits for operations or require us to install additional pollution control equipment, the costs of which could be significant.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Exploration, development, production and sale of oil and natural gas are subject to extensive federal, state, local and international regulation. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

- permits for drilling operations;
- drilling bonds;
- reports concerning operations;
- the spacing of wells;
- the rates of production;
- the plugging and abandoning of wells and decommissioning and removal of equipment;
- unitization and pooling of properties; and
- taxation.

Under these laws, we could be liable for property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially adversely affect our financial condition and results of operations.

We are responsible for the decommissioning, surface equipment removal, plugging, abandonment, and reclamation costs for our facilities.

We are responsible for compliance with all applicable laws and regulations regarding the decommissioning, surface equipment removal, plugging, abandonment, and reclamation of our facilities at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they will be a function of regulatory requirements at the time of decommissioning, surface equipment removal, plugging, abandonment, and reclamation. We may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund one or more decommissioning, surface equipment removal, plugging, abandonment, and reclamation reserve funds to provide for payment of future decommissioning, surface equipment removal, plugging, abandonment, and reclamation costs, which could decrease funds available to service debt obligations. In addition, such reserves, if established, may not be sufficient to satisfy such future decommissioning, surface equipment removal, plugging, abandonment, and reclamation costs and we will be responsible for the payment of the balance of such costs.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. Moreover, we may be required to write down our PUDs if we do not drill or plan on delaying those wells within the required five-year timeframe.

Should we fail to comply with all applicable regulatory agency administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 million per day for each violation. FERC may also impose administrative and criminal remedies and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and regulations pertaining to those and other matters may be considered or adopted by FERC from time to time. Additionally, the Federal Trade Commission (the “FTC”) has regulations intended to prohibit market manipulation in the petroleum industry with authority to fine violators of the regulations civil penalties of up to $1.0 million per day, and the CFTC, prohibits market manipulation in the markets regulated by the CFTC, including similar anti-manipulation authority with respect to oil swaps and futures contracts as that granted to the CFTC with respect to oil purchases and sales. The CFTC rules subject violators to a civil penalty of up to the greater of $1.0 million or triple the monetary gain to the person for each violation. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in “Business—Regulation of the Oil and Gas Industry.”

A change in the jurisdictional characterization of our natural gas assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our natural gas assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that our natural gas gathering pipelines meet the traditional test that FERC has used to determine whether a pipeline is a gathering pipeline and is, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and gathering services not subject to the jurisdiction of FERC, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our gathering facilities is subject to change based on future determinations by FERC, the courts or Congress. If FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the NGPA.

Such regulation could decrease revenue and increase operating costs. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by FERC.

FERC regulation may indirectly impact gathering services not directly subject to FERC regulation. FERC’s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect intrastate markets. In recent years, FERC has pursued procompetitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the natural gas gathering services.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, our natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. Our gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities.

We may be involved in legal proceedings that could result in substantial liabilities.

We may, from time to time, be a claimant or defendant to various legal proceedings, disputes and claims arising in the course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. Such legal proceedings are inherently uncertain and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices or operations, which could materially and adversely affect our business, operating results and financial condition. Accruals for such liability, penalties or sanctions may be insufficient. Judgments and estimates to determine accruals or range of losses related to legal and other proceedings could change from one period to the next, and such changes could be material.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into targeted geological formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and natural gas commissions. However, several federal agencies have asserted regulatory authority over certain aspects of the process.

For example, in February 2014, the EPA asserted regulatory authority pursuant to the SDWA UIC program over hydraulic fracturing activities involving the use of diesel and issued guidance covering such activities. Also, beginning in 2012, the EPA issued a series of regulations under the federal CAA that include NSPS, known as Subpart OOOO, for completions of hydraulically fractured natural gas wells and certain other plants and equipment and, in May 2016, published a final rule establishing new emissions standards, known as Subpart OOOOa, for methane and volatile organic compounds (“VOCs”) from certain new, modified and reconstructed equipment and processes in the oil and natural gas source category. The NSPS Subpart OOOO and OOOOa rules have since been subject to numerous legal challenges as well as EPA reconsideration proceedings and subsequent amendment proposals. More recently, in December 2023, EPA announced additional final NSPS OOOO program rules—referred to as Subparts OOOOb and OOOOc—which, once effective upon publication in the Federal Register, are expected to have a significant impact on the upstream and midstream oil and gas sectors from an operational cost perspective. Legal challenges to the expanded NSPS Subpart OOOO program rules are likely to follow, and accordingly, legal uncertainty exists with respect to the future scope and extent of implementation of the methane rule; however, even as currently implemented, these rules apply to our operations, including requirements for the installation of equipment to control VOC emissions from certain hydraulic fracturing of wells and fugitive emissions from well sites and other production equipment. Additional regulation could result in significant costs, including increased capital expenditures and operating and compliance costs, and could adversely impact or delay oil and natural gas production activities, which could have a material adverse effect on our business.

The BLM published a final rule in March 2015 that established new or more stringent standards relating to hydraulic fracturing on federal and American Indian lands. However, following years of litigation, the BLM rescinded the rule in December 2017. BLM’s repeal of the rule was challenged in court, and in March 2020, the Northern District of California issued a ruling in favor of the BLM. This ruling was appealed, but the case has been administratively closed since November 15, 2021. The regulations, if reinstated, may result in additional levels of regulation or complexity with respect to existing regulations that could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase costs of compliance. In addition, in May 2022, the U.S. Government Accountability Office released a study on methane emissions from oil and gas development, which included a recommendation that the BLM consider whether to require gas capture plans, including gas capture targets, from operators on federal lands. The reinstatement of the BLM hydraulic fracturing regulations or the promulgation of BLM gas capture regulations may result in additional levels of regulation or complexity that could lead to operational delays and increased operating and compliance costs that could make it more difficult and costly to perform hydraulic fracturing on federal and Indian lands.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. The final report concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that certain hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level.

From time to time, legislation has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, to date, such legislation has not been adopted. At the state level, Texas, where we conduct most of our operations, is among the states that has adopted regulations that impose new or more stringent permitting, including the requirement for hydraulic-fracturing operators to complete and submit a list of chemicals used during the fracking process. We may incur significant additional costs to comply with such existing state requirements and, in the event additional state level restrictions relating to the hydraulic-fracturing process are adopted in areas where we operate, we may become subject to additional permitting requirements and experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Moreover, we typically dispose of flowback and produced water or certain other oilfield fluids gathered from oil and natural gas producing operations in underground disposal wells. This disposal process has been linked to increased induced seismicity events in certain areas of the country, particularly in Oklahoma, Texas, Colorado, Kansas, New Mexico and Arkansas. These and other states have begun to consider or adopt laws and regulations that may restrict or otherwise prohibit oilfield fluid disposal in certain areas or 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. NMOCD and RRC have each imposed requirements in response to seismic events in the Permian Basin. See *"Recent regulatory restrictions on use of produced water and a moratorium on new produced water disposal wells in certain areas of the Permian Basin to stem rising seismic activity and earthquakes could increase our operating costs and adversely impact our business, results of operations and financial condition."* Any one or more of these developments may result in our having to limit disposal well volumes, disposal rates or locations, or to cease disposal well activities, or comply with more stringent analysis, recordkeeping, and notification requirements, which could have a material adverse effect on our business, financial condition, and results of operations.

Increased regulation and attention given to the hydraulic fracturing process and associated processes could lead to greater opposition to, and litigation concerning, oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells and an associated increase in compliance costs and time, which could have a material adverse effect on our liquidity, results of operations, and financial condition.

Climate change legislation and regulations restricting or regulating emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil, natural gas and NGLs that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional, and state levels of government to monitor and limit emissions of GHGs. While no comprehensive climate change legislation has been implemented at the federal level, the EPA and states or groupings of states have pursued legal initiatives in recent years that seek to reduce GHG emissions through efforts that include consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. In particular, the EPA has adopted rules under authority of the CAA that, among other things, establish certain permit reviews for GHG emissions from certain large stationary sources, which reviews could require securing permits at covered facilities emitting GHGs and meeting defined technological standards for those GHG emissions. The EPA has also adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore production. And, more recently, in August 2022, Congress passed the IRA, which includes requirements to impose fees beginning in 2025 on methane emissions from oil and gas operations that are required to report their GHG emissions under the EPA's GHG Reporting Rule.

Federal agencies also have begun directly regulating emissions of methane and GHG from oil and natural gas operations. In June 2016, the EPA published a final rule establishing NSPS Subpart OOOOa, which requires certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and VOC emissions. Furthermore, in November 2021 and November 2022, the EPA issued proposed rules which would update, strengthen, and expand the NSPS Subpart OOOO regulations for methane and VOC emissions from new, modified, and reconstructed sources. EPA has since announced in December 2023 the final version of these proposed rules, which are to be codified as NSPS Subparts OOOOb and OOOOc. Notably, the NSPS Subpart OOOOc rules include emissions guidelines to assist states in the development of plans to regulate methane emissions from certain existing sources, which had not previously been regulated under the NSPS Subpart OOOO programs. Legal challenges to the recently announced final NSPS Subparts OOOOb and OOOOc rules are likely to follow, and thus, the ultimate scope of these regulations remains uncertain. However, once effective upon publication in the Federal Register, the NSPS Subparts OOOOb and OOOOc rules are expected to have a significant impact on the upstream and midstream oil and gas sectors from an operational cost perspective.

The BLM also finalized rules regarding the control of methane emissions in November 2016 that applied to oil and natural gas exploration and development activities on public and tribal lands. The rules sought to minimize venting and flaring of emissions from storage tanks and other equipment, and also impose leak detection and repair requirements. However, due to subsequent BLM revisions and multiple legal challenges, the rules were never fully implemented, and in October 2020, the November 2016 rules were struck down by the District Court of Wyoming as the result of one such challenge. New Mexico and California have since filed an appeal of the Wyoming Court's decision in the Tenth Circuit.

Additionally, in December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the United States in April 2016 and entered into force in November 2016. This agreement does not create any binding obligations for nations to limit their GHG emissions. Nevertheless, President Biden has set ambitious targets for GHG reduction, including to achieve at least a 50 percent reduction from 2005 levels in economy-wide net GHG pollution by 2030.

Since 2012, annual reporting of GHGs has been required for persons operating certain types of industrial operations, including oil and gas production, transmission and storage operations that emit 25,000 metric tons or more of carbon dioxide equivalent per year. EPA has indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG emission limits. More recently, in August 2022, Congress passed the Inflation Reduction Act, which includes requirements to impose fees beginning in 2025 on methane emissions from oil and gas operations that are required to report their GHG emissions under the EPA’s GHG Reporting Rule. EPA’s proposed rule to implement the fee requirements, “Waste Emissions Charge for Petroleum and Natural Gas Systems,” was published on January 26, 2024, with comments due by March 11, 2024.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict or impose taxes or fees on emissions of GHGs could result in increased compliance costs or additional operating restrictions, and could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

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 typically include extralegal targets related to environmental stewardship, social responsibility, and corporate governance, have become an increasing focus of investors and shareholders across the industry. While reporting on ESG metrics remains voluntary, access to capital and investors is likely to favor companies with robust ESG programs in place.

Finally, increasing concentrations of GHG in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such climatic events were to occur, they could have an adverse effect on our financial condition and results of operations and the financial condition and operations of our customers.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling, and place us at a competitive disadvantage. Potential disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

Restrictions on drilling or other operational activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species and their habitats could prohibit drilling in certain areas or require the implementation of expensive mitigation or conservation measures. The designation or proposed designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have a material adverse impact on our ability to develop and produce our reserves.

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act, enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and of entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In December 2016, the CFTC re-proposed regulations implementing limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The Dodd-Frank Act and CFTC rules also will require us, in connection with certain derivatives activities, to comply with clearing and trade-execution requirements (or to take steps to qualify for an exemption to such requirements). In addition, the CFTC and certain banking regulators have adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception to the mandatory clearing, trade-execution and margin requirements for swaps entered to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, if any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow. It is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us or the timing of such effects. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil, natural gas and NGL prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and NGLs. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations.

Future federal, state or local legislation also may impose new or increased taxes or fees on oil and natural gas extraction or production.

Future changes in U.S. federal income tax laws, or the introduction of a carbon tax, as well as any similar changes in state law, could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural gas development, or increase costs, and any such changes could have an adverse effect on our financial position, results of operations, and cash flows. Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction or production. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil, natural gas or NGLs.

Anti-indemnity provisions enacted by many states may restrict or prohibit a party’s indemnification of us.

We typically enter into agreements with our customers governing the use and operation of our systems, which usually include certain indemnification provisions for losses resulting from operations. Such agreements may require each party to indemnify the other against certain claims regardless of the negligence or other fault of the indemnified party; however, many states place limitations on contractual indemnity agreements, particularly agreements that indemnify a party against the consequences of its own negligence. Furthermore, certain states, including Louisiana, New Mexico, Texas and Wyoming have enacted statutes generally referred to as “oilfield anti-indemnity acts” expressly prohibiting certain indemnity agreements contained in or related to oilfield services agreements. Such anti-indemnity acts may restrict or void a party’s indemnification of us, which could have a material adverse effect on our business, financial condition, prospects and results of operations.

Our effective tax rate may change in the future, which could adversely impact us.

The TCJA significantly changed the U.S. federal income taxation of U.S. corporations, including by reducing the U.S. corporate income tax rate, limiting interest deductions and certain deductions for executive compensation, permitting immediate expensing of certain capital expenditures, and revising the rules governing net operating losses. The TCJA remains unclear in some respects and continues to be subject to potential amendments and technical corrections. The United States Treasury Department and the IRS have issued significant guidance since the TCJA was enacted, interpreting the TCJA and clarifying some of the uncertainties, and are continuing to issue new guidance. There are still significant aspects of the TCJA for which further guidance is expected, and both the timing and contents of any such future guidance are uncertain.

Further, changes to the U.S. federal income tax laws are proposed regularly and there can be no assurance that, if enacted, any such changes would not have an adverse impact on us. For example, President Biden has suggested the reversal or modification of some portions of the TCJA and certain of these proposals, if enacted, could increase our effective tax rate. There can be no assurance that any such proposed changes will be introduced as legislation or, if introduced, later enacted, and, if enacted, what form such enacted legislation would take. Such changes could potentially have retroactive effect.

In light of these factors, there can be no assurance that our effective income tax rate will not change in future periods. If the effective tax rate were to increase as a result of the future legislation, our business could be adversely affected.

Risks Related to Our Common Stock

The market price of our common stock may be volatile, which could cause the value of your investment to decline.

The stock markets have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. The market price of our common stock may also fluctuate significantly in response to the following factors, some of which are beyond our control:

- our operating and financial performance and drilling locations, including reserve estimates;
- actual or anticipated fluctuations in our quarterly results of operations, and financial indicators, such as net income, cash flow and revenues;
- our failure to meet revenue, reserves or earnings estimates by research analysts or other investors;
- sales of our common stock by the Company or other stockholders, or the perception that such sales may occur;
- the public reaction to our press releases, other public announcements, and filings with the SEC;
- strategic actions by our competitors or competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- publication of research reports about us or the oil and natural gas exploration and production industry generally;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our common stock;
- increases in market interest rates or funding rates, which may increase our cost of capital;
- changes in market valuations of similar companies;
- changes in accounting principles, policies, guidance, interpretations or standards;
- additions or departures of key management personnel;
- actions by our stockholders;
- commencement or involvement in litigation;
- general market conditions, including fluctuations in commodity prices;
- political conditions in oil and natural gas producing regions;
- domestic and international economic, legal and regulatory factors unrelated to our performance; and
- the realization of any risks described under this "*Risk Factors*" section.

In the past, following periods of volatility in the market price of a company's securities, stockholders have often instituted class action securities litigation against those companies. Such litigation, if instituted, could result in substantial costs and diversion of management attention and resources, which could significantly harm our business, financial condition, results of operations and reputation.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

Future sales or the availability for sale of substantial amounts of our common stock in the public market, or the perception that such sales could occur, could adversely affect the prevailing market price of our common stock and could impair our ability to raise capital through future sales of equity securities.

On April 7, 2021, we filed with the SEC a "shelf" registration statement on Form S-3 that became effective on May 12, 2021. The registration statement registers securities that may be issued by the Company in a maximum aggregate amount of up to $250,000,000, as well as up to 16,721,922 shares of common stock that may be resold by certain selling stockholders named in therein. On September 1, 2023, we filed a prospectus supplement for the sale of up to $50,000,000 of shares of our common stock in an ATM offering under the shelf registration statement, of which approximately $0.3 million was sold under the ATM as of December 31, 2023. Sales by the Company of common stock under the ATM or other sales by the Company of securities under a registration statement or in private placements, could be dilutive to existing shareholders. Additionally, sales by the Company or selling stockholders of securities, or the perception that such sales may occur, could adversely affect the trading price for our common stock.

We may issue shares of our common stock or other securities from time to time as consideration for future acquisitions and investments. If any such acquisition or investment is significant, the number of shares of our common stock, or the number or aggregate principal amount, as the case may be, of other securities that we may issue may in turn be substantial. We may also grant registration rights covering those shares of our common stock or other securities in connection with any such acquisitions and investments.

We cannot predict the size of future issuances of our common stock or sales by our selling stockholders or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares of our common stock issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

If we fail to continue to meet the requirements for continued listing on the NYSE American stock exchange, our common stock could be delisted from trading, which would decrease the liquidity of our common stock and ability to raise additional capital.

Our common stock is listed for quotation on the NYSE American and we are required to meet specified financial requirements, including requirements for a minimum amount of capital, a minimum price per share, a minimum public float, and continued business operations so that we are not delisted or characterized as a "public shell company." If we are unable to comply with the NYSE American stock exchange's listing standards, NYSE may determine to delist our common stock from the NYSE American stock exchange or other of NYSE's trading markets. If our common stock is delisted for any reason, it could reduce the value of our common stock and liquidity.

If securities analysts do not publish research or reports about our business or if they publish negative evaluations of our stock, the price of our stock could decline.

The trading market for our common stock relies, in part, on the research and reports that industry or financial analysts publish about us or our business. Equity research analysts may elect not to provide research coverage of our common stock, and such lack of research coverage may adversely affect the market price of our common stock. In the event we do have equity research analyst coverage, we will not have any control over the analysts or the content and opinions included in their reports. The price of our common stock could decline if one or more equity research analysts downgrade our stock or issue other unfavorable commentary or research. If one or more equity research analysts ceases coverage of us or fails to publish reports on us regularly, demand for our common stock could decrease, which in turn could cause our stock price or trading volume to decline.

We may not generate sufficient cash to support any dividend to our common stockholders.

The amount of any dividend will depend on the amount of cash we generate from operations, which will fluctuate from quarter to quarter based on, among other things:

- the volumes of crude oil, natural gas and NGLs that we produce;
- market prices of crude oil, natural gas and NGLs and their effect on our drilling and development plan;
- the levels of our operating expenses, maintenance expenses and general and administrative expenses;
- regulatory action affecting:
- the supply of, or demand for, crude oil, natural gas and NGLs;
- our operating costs or our operating flexibility;
- prevailing economic conditions; and
- adverse weather conditions.

In addition, the actual amount of cash we will have available for dividends will depend on other factors, some of which are beyond our control, including:

- our debt service requirements and other liabilities;
- our ability to borrow under our debt agreements to fund our capital expenditures and operating expenditures and to pay dividends;
- fluctuations in our working capital needs;
- restrictions on dividends contained in any of our debt agreements;
- the cost of acquisitions, if any; and
- other business risks affecting our cash levels.

Our quarterly cash dividends, if any, may vary significantly both quarterly and annually.

Investors who are looking for an investment that will pay regular and predictable quarterly dividends should not invest in our common stock. Our business performance may be more volatile, and our cash flow may be less stable, than other business models that pay dividends. The amount of our quarterly dividends will generally depend on the performance of our business, which has a limited operating history.

The Board may modify or revoke our dividend policy at any time at its discretion.

We are not required to pay any dividends on our common stock at all. Accordingly, the Board may change our dividend policy at any time at its discretion and could elect not to pay dividends on our common stock for one or more quarters. Any modification or revocation of our cash dividend policy could substantially reduce or eliminate the amounts of dividends to our common stockholders. The amount of dividends we make, if any, and the decision to make any dividend at all will be determined by our Board, whose interests may differ from those of our common stockholders.

The amount of cash we have available for dividends to our common stockholders depends primarily on our cash flow and not solely on our profitability, which may prevent us from paying dividends, even during periods in which we record net income.

The amount of cash we have available for dividends depends primarily upon our cash flow and not solely on our profitability, which will be affected by non-cash items. As a result, we may pay cash dividends during periods when we record a net loss for financial accounting purposes and, conversely, we might fail to pay cash dividends on our common stock during periods when we record net income for financial accounting purposes.

Delaware law imposes restrictions on our ability to pay cash dividends on our common stock.

Our common stockholders do not have a right to dividends on such shares unless declared or set aside for payment by our Board. Under Delaware law, cash dividends on capital stock may only be paid from “surplus” or, if there is no “surplus,” from the corporation’s net profits for the then-current or the preceding fiscal year. Unless we operate profitably, our ability to pay dividends on our common stock would require the availability of adequate “surplus,” which is defined as the excess, if any, of net assets (total assets less total liabilities) over capital. Our business may not generate sufficient surplus or net profits from operations to enable us to pay dividends on our common stock.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our shareholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our Board may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Risks Related to the Company

If we fail to maintain an effective system of internal control over financial reporting, we may not be able to accurately report our financial results or prevent fraud. As a result, stockholders could lose confidence in our financial and other public reporting, which would harm our business and the trading price of our common stock.

Effective internal control over financial reporting is necessary for us to provide reliable financial reports and, together with adequate disclosure controls and procedures, is designed to prevent fraud. Any failure to implement required new or improved controls, or difficulties encountered in their implementation, could cause us to fail to meet our reporting obligations. In addition, any testing, as and when required, conducted in connection with Section 404 of the Sarbanes-Oxley Act or any subsequent testing by our independent registered public accounting firm, as and when required, may reveal deficiencies in our internal control over financial reporting that are deemed to be significant deficiencies or material weaknesses or that may require prospective or retroactive changes to our financial statements or identify other areas for further attention or improvement. Inferior internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock.

We are a smaller reporting company and we cannot be certain if the reduced disclosure requirements applicable to smaller reporting companies will make our common stock less attractive to investors.

We are currently a “smaller reporting company” as defined by Rule 12b-2 of the Exchange Act. As a “smaller reporting company,” we are subject to reduced disclosure obligations in our SEC filings compared to other issuers, including, among other things, being required to provide only two years of audited financial statements in annual reports and being subject to simplified executive compensation disclosures. Until such time as we cease to be a “smaller reporting company,” such reduced disclosure in our SEC filings may make it harder for investors to analyze our operating results and financial prospects. If some investors find our common stock less attractive as a result of any choices to reduce disclosure we may make, there may be a less active trading market for our common stock and our stock price may be more volatile.

Our business and operations could be adversely affected if we lose key personnel.

We depend to a large extent on the services of our officers, including Bobby Riley, our Chief Executive Officer and President, Philip Riley, our Chief Financial Officer and Executive Vice President – Strategy , Corey Riley, our Executive Vice President – Business Intelligence, and Michael Palmer, our Executive Vice President Corporate – Land. These individuals have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties and developing and executing financing strategies. The loss of any of these individuals could have a material adverse effect on our operations. We do not maintain key-man life insurance with respect to any management personnel. Our success will be dependent on our ability to continue to retain and utilize skilled technical personnel. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition, and results of operations.

Our executive officers, directors and principal stockholders have the ability to control or significantly influence all matters submitted to the Company’s stockholders for approval.

As of December 31, 2023, our executive officers, directors and principal stockholders, in the aggregate, ow n 67.5% of the fully diluted common stock of the Company. As a result, if these stockholders were to choose to act together, they would be able to control or significantly influence all matters submitted to the Company’s stockholders for approval, as well as the Company’s management and affairs. For example, these persons, if they choose to act together, would control or significantly influence the election of directors and approval of any merger, consolidation or sale of all or substantially all of the Company’s assets. This concentration of voting power could delay or prevent an acquisition of the Company on terms that other stockholders may desire.

Provisions in our corporate charter documents and under Delaware law could make an acquisition of the Company, which may be beneficial to our stockholders, more difficult and may prevent attempts by our stockholders to replace or remove current management.

Provisions in our corporate charter and by-laws may discourage, delay or prevent a merger, acquisition or other changes in control that stockholders may consider favorable, including transactions in which stockholders might otherwise receive a premium for their shares. These provisions also could limit the price that investors might be willing to pay in the future for shares of our common stock, thereby depressing the market price of our common stock. In addition, because our Board is responsible for appointing the members of the management team, these provisions may frustrate or prevent any attempts by our stockholders to replace or remove current management by making it more difficult for stockholders to replace members of our board of directors. Among other things, these provisions:

- allow the authorized number of directors to be changed only by resolution of the Board;
- after a certain date, limit the manner in which stockholders can remove directors from the Board;
- establish advance notice requirements for stockholder proposals that can be acted on at stockholder meetings and nominations to the Board;
- after a certain date, require that stockholder actions must be effected at a duly called stockholder meeting and prohibit actions by written consent;
- limit who may call stockholder meetings;
- authorize the Board to issue preferred stock without stockholder approval, which could be used to institute a shareholder rights plan, or so-called “poison pill,” that would work to dilute the stock ownership of a potential hostile acquirer, effectively preventing acquisitions that have not been approved by the Board; and
- after a certain date, require the approval of the holders of at least 66 2/3% of the votes that all the stockholders would be entitled to cast to amend or repeal certain provisions of our charter or bylaws.

Our bylaws provide that the Court of Chancery of the State of Delaware will be the exclusive forum for substantially all disputes between the Company and its stockholders, which could limit stockholders’ ability to obtain a favorable judicial forum for disputes with the Company or its directors, officers, employees or stockholders.

Our bylaws provide that, unless the Company consents in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware is the exclusive forum for any derivative action or proceeding brought on the Company’s behalf, any action asserting a breach of fiduciary duty owed by Company’s directors, officers, other employees or stockholders to the Company or its stockholders, any action asserting a claim against the Company arising pursuant to the Delaware General Corporation Law or as to which the Delaware General Corporation Law confers jurisdiction on the Court of Chancery of the State of Delaware, or any action asserting a claim arising pursuant to the Company’s certificate of incorporation or bylaws or governed by the internal affairs doctrine.

Our bylaws provide that, unless the Company consents in writing to the selection of an alternative forum, the federal district courts of the United States of America shall, to the fullest extent permitted by law, be the sole and exclusive forum for any actions arising under the Securities Act of 1933, as amended, or the Exchange Act.

These provisions may limit a stockholder’s ability to bring a claim in a judicial forum that it finds favorable for disputes with the Company or its directors, officers, employees or stockholders, which may discourage such lawsuits against the Company and its directors, officers, employees or stockholders. Alternatively, if a court were to find these provisions in our bylaws to be inapplicable or unenforceable in an action, the Company may incur additional costs associated with resolving such action in other jurisdictions, which could adversely affect our business and financial condition.

Conflicts of interest could arise in the future between us, on the one hand, and certain of our stockholders and their respective affiliates, including their funds and their respective portfolio companies, on the other hand, concerning among other things, potential competitive business activities or business opportunities.

Investment funds managed by certain of our stockholders are in the business of making investments in entities in the U.S. energy industry. As a result, certain of our stockholders may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. Certain of our stockholders and their respective portfolio companies may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Under our certificate of incorporation, certain of our stockholders and/or one or more of their respective affiliates are permitted to engage in business activities or invest in or acquire businesses which may compete with our business or do business with any client of ours. Any actual or perceived conflicts of interest with respect to the foregoing could have an adverse impact on the trading price of our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 1C. Cybersecurity

Cybersecurity Risk Management and Strategy

Riley Permian recognizes the importance of assessing, identifying, and managing material risks associated with cybersecurity threats, as is defined in Item 106 (a) of Regulation S-K. These risks include, among other things: operational risks, harm to our employees, suppliers or industry partners, intellectual property theft, fraud, extortion, and violation of data privacy or security laws. We use a risk management framework based on applicable laws and regulations, and informed by industry standards and industry-recognized practices for identifying and managing cybersecurity risks within our operations, infrastructure, and corporate resources.

Our cybersecurity program is built upon internationally recognized frameworks and maps to standards published by The National Institute of Standards and Technology ("NIST CSF"), which develops cybersecurity standards, guidelines, best practices and other resources to meet the needs of U.S. industry, federal agencies and the broader public. Utilizing monitoring technologies in conjunction with a well-established framework of policies, procedures and controls, our processes provide us with the structure to detect and respond to cyber threats, thereby mitigating the risk of potential cybersecurity issues. In addition, we conduct reoccurring security awareness training, penetration tests, and vulnerability assessments to identify any potential threats or vulnerabilities in our systems. Our processes to assess, identify and manage material risks from cyber threats include the risks arising from threats associated with third party service providers, including cloud-based platforms.

We have developed a robust cyber incident response plan which provides a documented framework for handling high severity security incidents and facilitates coordination across a cross-disciplinary team of employees, legal counsel and third party service providers. Our information security team, which is part of our IT department, constantly monitors threat intelligence feeds, handles vulnerability management, responds to incidents and reports to the Information Security Coordinator. Upon detection of an event that meets certain assessment thresholds, the Information Security Coordinator reports such matters to the Incident Response Team, who then review the event and report to senior management, the cyber committee or our Board as appropriate. Cybersecurity events and data incidents are evaluated, ranked by severity and prioritized for response and remediation. Incidents are evaluated to determine materiality as well as operational and business impact, and reviewed for privacy impact.

Internally, we have developed a cybersecurity awareness program which includes training that reinforces our information technology and security policies, standards and practices, and we require that our employees comply with these policies. The cybersecurity awareness program offers training on how to identify potential cybersecurity risks and protect our resources and information. Finally, our privacy program requires all employees to take periodic awareness training on data privacy. This training includes information about confidentiality and security, as well as responding to unauthorized access to or use of information.

From time to time, we engage third-party service providers to enhance our risk mitigation efforts. For example, we have engaged a multifaceted cybersecurity advisory firm specializing in risk management and compliance, to perform annual cybersecurity risk assessments utilizing industry standard cybersecurity frameworks.

We also purchase insurance to protect us against the risk of cybersecurity breaches. Our Vice President of Finance and Treasurer is responsible for our insurance policies and reviews on a regular basis our cyber insurance policy with management to ensure we have appropriate coverage. We have business continuity, contingency and disaster recovery plans and procedures in place in the event of a cybersecurity incident. These plans are tested in conjunction with the Company’s annual testing of its cybersecurity incident response readiness and reporting through tabletop exercises.

To date, risks from cybersecurity threats have not previously materially affected us, and we currently do not expect that the risks from cybersecurity threats are reasonably likely to materially affect us, including our business, strategy, results of operations or financial condition. That said, as discussed more fully under “Item 1A – Risk Factors”, the sophistication of cyber threats continues to increase, and the preventative actions we take to reduce the risk of cyber incidents and protect our systems and information may be insufficient. Accordingly, no matter how well designed or implemented our controls are, we will not be able to anticipate all security breaches of these types, including security threats that may result from third parties improperly employing AI technologies, and we may not be able to implement effective preventive measures against such security breaches in a timely manner.

Governance

Role of our Board of Directors

The Nominating and Corporate Governance Committee of the Board of Directors is primarily responsible for the oversight of our information security programs and cybersecurity incident response plans. We established a cyber subcommittee comprised of our senior management team that reports directly to the Board and its Committees regarding our cyber risks and threats, the status of initiatives strengthen our information security systems, assessments of our cybersecurity program and incident response plan, and our views of the emerging threat landscape. Our Executive Vice President – Business Intelligence and our head of Internal Audit report directly to the Nominating and Corporate Governance Committee as well as the Audit Committee regarding these matters and are responsible for reporting to the Committees on our company-wide enterprise risk assessment, and that assessment also includes an evaluation of cyber risks and threats. The Chair of the Nominating and Corporate Governance Committee regularly reports to the Board of Director on cybersecurity risks and other matters reviewed by the Nominating and Corporate Governance Committee in conjunction with the management team. All materials or presentations on cybersecurity provided to the Nominating and Corporate Governance Committee are provided to all Board members.

As a matter of process, the Nominating and Corporate Governance Committee annually reviews, and recommends to the Board of Directors its approval of, our information security policy and cybersecurity program and our incident response plans. Furthermore, on an annual basis, the Board of Directors and its Committees review and discuss our technology strategy with our Executive Vice President – Business Intelligence and approve our technology strategic plan.

Role of our Management Team

Our Executive Vice President - Business Intelligence is responsible for the day-to-day management of our cybersecurity risks and for recommending the strategies and technologies used by the organization to collect, integrate and analyze business information to support the organization's strategic decisions. He is supported by a cross-disciplinary team from the Company’s accounting, legal and risk oversight functions and its internal audit group. This incident response team meets quarterly and as needed to review the Company’s cybersecurity risk management initiatives and progress and cybersecurity metrics. On an annual basis, the incident response team coordinates a cybersecurity risk assessment. In the event of a suspected cybersecurity incident, the team will coordinate the Company’s evaluation, subsequent response and any updates to the cybersecurity risk management program with executive management and the cyber subcommittee.

We have a security incident response framework in place. We use this incident response framework as part of the process we employ to keep our management and Board of Directors informed about and monitor the prevention, detection, mitigation, and remediation of cybersecurity incidents. The framework is a set of coordinated procedures and tasks that our incident response team, under the direction of the Information Security Officers, executes with the goal of ensuring timely and accurate resolution of cybersecurity incidents. Our cybersecurity framework includes regular compliance assessments with our policies and standards and applicable state and federal statutes and regulations. In addition, we validate compliance with our internal data security controls through the use of security monitoring utilities and internal and external audits.

Our Information Security Coordinator, members of our incident response team and our third party consultants each have extensive experience in the information technology area. The Executive Vice President of Business Intelligence has over 10 years of experience in the information technology area and holds a Master of Business Administration with a focus in Technology from Oklahoma Christian University. Additionally, our Vice President of Technology and Analytics has 10 years of professional experience in the information security area.

Additionally, our management team's internal cybersecurity risk management and strategy processes are supported with third party consultants with extensive work experience in various roles involving information technology, including security, auditing, compliance, systems and programming. These individuals are informed about, and monitor the prevention, mitigation, detection and remediation of cybersecurity incidents through their management of, and participation in, the cybersecurity risk management and strategy processes described above, including the operation of our incident response plan, and report to the

Board of Directors, Nominating and Corporate Governance Committee and Audit Committee, as the case may be, on any appropriate items.

Item 3. Legal Proceedings

We may, from time to time, be a claimant or defendant to various legal proceedings, disputes and claims arising in the course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the oil and natural gas industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

See Note 13 - Commitments and Contingencies in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a discussion of our commitments and contingencies.

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

Shares of our common stock are listed on the NYSE American under the symbol "REPX". There were approximately 125 holders of record of our common stock as of February 29, 2024.

Dividends

The Company declared quarterly dividends totaling approximately $27.9 million and $25.3 million for the years ended December 31, 2023 and 2022, respectively. The cash dividends were declared for all issued and outstanding common shares including unvested restricted stock issued under the Company's Amended and Restated 2021 Long-Term Incentive Plan.

The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our Board. Our Board's determination of 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, restrictions imposed by applicable law and other factors that the Board deems relevant at the time of such determination. The Company's Credit Facility and Senior Notes can limit the dividends the Company is able to pay unless the Company meets certain covenants in accordance with its credit agreement and the terms of the Senior Notes.

Outstanding Equity Awards

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (excluding securities in Column (a))
	(a)	(b)	(c)
Equity Compensation Plans Approved by Security Holders	—	—	1,075,626
Equity Compensation Plans Not Approved by Security Holders	—	—	—
Total	—	—	1,075,626

Unregistered Sales of Equity Securities

None.

Issuer Repurchases of Equity Securities

Our common stock repurchase activity during the fourth quarter of 2023 was as follows:

Month Ended	Total Number of Shares Purchased[1]		Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plan or Programs
October 31	32,348	$	31.80	—	—
November 30	170	$	29.05	—	—
December 31	—	$	—	—	—

(1) These amounts reflect the shares received by us from employees for the payment of personal income tax withholding on vesting transactions. The acquisition of the surrendered shares was not part of a publicly announced program to repurchase shares of our common stock. Any shares repurchased by the Company for personal tax withholdings are immediately retired upon repurchase.

Item 6. Selected Financial Data

[Reserved]

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

The following discussion and analysis of the Company's financial condition and results of operations should be read in conjunction with the Company's consolidated financial statements and related notes thereto presented in this Annual Report. The following discussion contains "forward-looking statements" that reflect the Company's future plans, estimates, beliefs and expected performance. The Company's actual results could differ materially from those discussed in these forward-looking statements. See "Cautionary Statement Regarding Forward-Looking Statements" and "Part I. Item 1A. Risk Factors."

Overview

We operate in the upstream segment of the oil and natural gas industry and are focused on steadily growing conventional reserves, production and cash flow through the acquisition, exploration, development and production of oil, natural gas and NGLs primarily in the Permian Basin in West Texas and Southeastern New Mexico. We intend to continue to develop our reserves and increase production through development drilling and exploration activities and through acquisitions that meet our strategic and financial objectives.

Financial and Operating Highlights

Financial and operating results reflect the following:

- Increased total net equivalent production by 62% to 18.6 MBoe/d for the year ended December 31, 2023, as compared to the year ended December 31, 2022
- During the year ended December 31, 2023, 24 gross (18.2 net) horizontal wells were brought online to production
- Realized average combined price on production sold of $54.91 per Boe, before derivative settlements, during the year ended December 31, 2023, including $75.62 per barrel for oil
- Generated cash flow from operations of $207.2 million for the year ended December 31, 2023
- Incurred total accrual (activity based) capital expenditures before acquisitions of $135.8 million for the year ended December 31, 2023 as compared to $123.1 million for the year ended December 31, 2022
- Paid cash dividends on common shares of $27.7 million during the year ended December 31, 2023
- $15.3 million in cash and $356.0 million in total debt as of December 31, 2023

Recent Developments

Market Conditions, Commodity Prices and Interest Rates

The U.S. and global economies and markets have experienced heightened volatility following impactful geopolitical events, the effects of widespread inflation and the impact of significantly higher interest rates. Prices for oil and natural gas are determined primarily by prevailing market conditions, which have been and could continue to be volatile.

The combination of geopolitical events, inflation and the rising interest rate environment has led to increasing forecasts of a U.S. or global recession. Any such recession could prolong market volatility or cause a decline in commodity prices, among other potential impacts.

The Company cannot estimate the length or gravity of the future impact these events will have on the Company's results of operations, financial position, liquidity and the value of oil and natural gas reserves.

New Mexico Acquisition

On April 3, 2023, the Company completed the New Mexico Acquisition from Pecos for an adjusted purchase price of $325 million. The New Mexico Acquisition was funded through a combination of borrowings under the Company's Credit Facility and proceeds from the issuance of $200 million of Senior Notes.

Power Joint Venture

In January 2023, the Company entered into an agreement to form a joint venture created for the purpose of constructing a new power infrastructure for onsite, baseload power generation using produced natural gas for its Champions Field. The Company has an initial 30% investment in the joint venture company, RPC Power LLC, and is committed to providing its portion of capital. Construction of the onsite power generation facility was predominately completed during 2023 with temporary power generation beginning in November 2023 and the onsite power generation facility expected to be operational in spring of 2024.

Results of Operations

Comparison for the years ended December 31, 2023 and 2022

The following table sets forth selected operating data for the years ended December 31, 2023 and 2022:

	Years Ended December 31,	
	2023	2022
Revenues (in thousands):		
Oil sales	$ 363,125	$ 298,723
Natural gas sales	2,612	10,755
NGLs	6,910	9,865
Oil and natural gas sales, net	$ 372,647	$ 319,343
Production Data, net:		
Oil (MBbls)	4,802	3,217
Natural gas (MMcf)	5,865	3,229
NGLs (MBbls)	1,006	444
Total (MBoe)	6,786	4,199
Daily combined volumes (Boe/d)	18,590	11,505
Daily oil volumes (Bbls/d)	13,156	8,814
Average Realized Prices:		
Oil ($ per Bbl)	$ 75.62	$ 92.86
Natural gas ($ per Mcf)	0.45	3.33
NGLs ($ per Bbl)	6.87	22.22
Combined ($ per Boe)	$ 54.91	$ 76.05
Average Realized Prices, including derivative settlements: (1)		
Oil ($ per Bbl)	$ 71.93	$ 71.75
Natural gas ($ per Mcf)	0.53	1.06
NGLs ($ per Bbl)	6.87	22.22
Combined ($ per Boe)	$ 52.38	$ 58.13

(1) The Company's calculation of the effects of derivative settlements includes losses on the settlement of its commodity derivative contracts. These losses are included under other income (expense) on the Company's consolidated statements of operations.

Oil and Natural Gas Revenues

Our revenues are derived from the sale of our oil and natural gas production, including the sale of NGLs that are extracted from our natural gas during processing. Revenues from product sales are a function of the volumes produced, product quality, market prices, gas Btu content, as well as midstream counterparty fees and deducts. Our revenues from oil, natural gas and NGL sales do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in the volume of production sold or changes in commodity prices. The Company’s total oil and natural gas revenue, net increased $53.3 million, or 17%, for the year ended December 31, 2023 compared to the year ended December 31, 2022. The Company’s realized average combined price on its production for the year ended December 31, 2023 decreased by $21.14 per Boe, or 28% compared to the year ended December 31, 2022.

Oil revenues

- For the year ended December 31, 2023, oil revenues increased by $64.4 million, or 22%, compared to the year ended December 31, 2022. Of the increase, $147.2 million was attributable to an increase in volume, which was partially offset by $82.7 million attributable to a decrease in our realized price. Volumes increased by 49%, while realized prices decreased by 19% as compared to the year ended December 31, 2022. The oil and natural gas properties acquired in the New Mexico Acquisition contributed $71.9 million to the Company's oil revenues for the 2023 period.

- Oil volumes increased during the year ended December 31, 2023 due to oil and natural gas assets acquired in the New Mexico Acquisition, production from new wells and workovers performed on existing wells. During the year ended December 31, 2023, we brought online 24 gross (18.2 net) horizontal wells. The New Mexico Acquisition contributed oil volumes of approximately 931 MBbls for the 2023 period.

- The average WTI price decreased by $17.32 per Bbl during the year ended December 31, 2023 when compared to the year ended December 31, 2022.

Natural gas revenues

- For the year ended December 31, 2023, natural gas revenues decreased by $8.1 million, or 76%, compared to the year ended December 31, 2022. Realized natural gas prices decreased by 87% partially offset by an increase in volumes of 82% as compared to the year ended December 31, 2022. The oil and natural gas properties acquired in the New Mexico Acquisition contributed $2.1 million to the Company's natural gas revenues for the 2023 period.

- Natural gas sales volumes increased during the year ended December 31, 2023 compared to the year ended December 31, 2022 due to oil and natural gas properties acquired in the New Mexico Acquisition, production from new wells and workovers performed on existing wells. The New Mexico Acquisition contributed 2,179 MMcf to the Company's natural gas volumes for the 2023 period.

- The average Henry Hub price decreased by $3.92 per Mcf during the year ended December 31, 2023 compared to the year ended December 31, 2022.

NGLs revenues

- For the year ended December 31, 2023, NGL revenues decreased by $3.0 million, or 30%, compared to the year ended December 31, 2022. Realized prices decreased by 69%, partially offset by an increase in volumes of 126% as compared to the year ended December 31, 2022. The oil and natural gas properties acquired in the New Mexico Acquisition contributed $5.3 million to the Company's NGL revenues for the 2023 period.

- NGL sales volumes increased during the year ended December 31, 2023 compared to the year ended December 31, 2022 due to the New Mexico Acquisition, production from new wells and workovers performed on existing wells. The oil and natural gas properties acquired in the New Mexico Acquisition contributed 451 MBbls to the Company's NGL volumes for the 2023 period.

Contract Services - Related Party

The following table presents the Company's revenue and costs associated with its contract services - related party transactions:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Contract services - related parties [1]	$ 2,400	$ 2,400
Cost of contract services - related parties [2]	579	450
Gross profit from contract services	$ 1,821	$ 1,950

(1) The Company's contract services - related parties revenue is derived from master services agreements with related parties to provide certain administrative support services.

(2) The Company's cost of contract services - related parties represents costs specifically attributable to the master service agreements the Company has in place with the respective related parties.

Costs and Expenses

The following table presents the Company's operating costs and expenses and other (income) expenses:

	Year Ended December 31,	
	2023	2022
Costs and Expenses:	(In thousands)	
Lease operating expenses	$ 58,817	$ 32,458
Production and ad valorem taxes	$ 25,559	$ 19,273
Exploration costs	$ 4,165	$ 2,032
Depletion, depreciation, amortization and accretion	$ 65,055	$ 32,113
Impairment of oil and natural gas properties	$ 9,760	$ 7,325
Administrative costs	$ 26,569	$ 18,496
Share-based compensation	6,833	3,439
General and administrative expense	$ 33,402	$ 21,935
Transaction costs	$ 5,817	$ 2,638
Interest expense, net	$ 31,816	$ 1,090
(Gain) loss on derivatives, net	$ (6,193)	$ 51,574
Income tax expense	$ 34,461	$ 32,844

Lease Operating Expenses ("LOE")

LOE are the costs incurred in the operation and maintenance of producing properties. Expenses for electricity, compression, direct labor, saltwater disposal and materials and supplies comprise the most significant portion of our lease operating expenses. Certain operating cost components, 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. For instance, repairs to our pumping equipment or surface facilities or subsurface maintenance result in increased production expenses in periods during which they are performed. Certain operating cost components, such as saltwater disposal associated with produced water, are variable and increase or decrease as hydrocarbon production levels and the volume of completion water disposal increases or decreases.

The Company's LOE increased by $26.4 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. For the year ended December 31, 2023, the increase was driven by a $20.0 million increase due to higher production, including $13.3 million attributable to the New Mexico Acquisition, and a $10.1 million increase due to higher workover expense, including $7.6 million attributable to the New Mexico Acquisition, partially offset by a $3.7 million decrease primarily related to lower utility rates.

Production and Ad Valorem Tax Expense

Production taxes are paid on produced oil, natural gas and NGLs based on a percentage of revenues at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to changes in our oil, natural gas and NGL revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties, which also trend with oil and natural gas prices and vary across the different counties in which we operate.

Production and ad valorem taxes increased by $6.3 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. Production taxes increased primarily due to increases in our oil and natural gas sales, net, including revenues from production associated with the oil and natural gas properties acquired in the New Mexico Acquisition, partially offset by lower commodity prices. Ad valorem taxes increased for the year ended December 31, 2023 based on higher estimated property values and higher tax rates for the current taxable period.

Exploration Costs

Exploration costs consist of exploratory well expense, expiration of unproved leasehold, and geological and geophysical costs which include seismic survey costs. The following table presents exploration costs for the years ended December 31, 2023 and 2022:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Exploratory well expense[(1)]	$ 3,447	$ —
Expiration of unproved leasehold	696	1,953
Geological and geophysical costs	22	79
Total exploration costs	$ 4,165	$ 2,032

(1) The Company determined that an exploratory well was not capable of producing commercial quantities and expensed the associated drilling costs during the year ended December 31, 2023,

Depletion, Depreciation, Amortization and Accretion Expense

Depletion, depreciation and amortization is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil, natural gas and NGLs. All costs incurred in the acquisition, exploration and development of properties (excluding costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration activities) are capitalized. Capitalized costs are depleted using the units-of-production method.

Accretion expense relates to ARO. We record the fair value of the liability for ARO in the period in which the liability is incurred (at the time the wells are drilled or acquired) with the offset to property cost. The liability accretes each period until it is settled or the well is sold, at which time the liability is removed.

Depletion, depreciation, amortization and accretion expense increased by $32.9 million for the year ended December 31, 2023, compared to the year ended December 31, 2022. The increase for the year ended December 31, 2023 was primarily due to depletion associated with the oil and natural gas acquired in the New Mexico Acquisition and higher production on historical properties along with a higher depletion rate on the historical properties.

Impairment of Oil and Natural Gas Properties

The cost of proved oil and natural gas properties are assessed on a field-by-field basis for impairment at least annually or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We compare the expected undiscounted future cash flows of the oil and natural gas properties to the carrying amount of the oil, natural gas and NGL properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we adjust the carrying amount of the oil and natural gas properties to estimated fair value.

During the year ended December 31, 2023, the Company recognized an impairment loss on proved properties of $9.8 million relating to certain properties in Texas outside of the Company's acreage in the Champions Field. This impairment was primarily driven by notably lower commodity pricing at the time of measurement of fair value at year-end 2023. The Company recognized an impairment loss on proved properties of $7.3 million for the year ended December 31, 2022, which related to a decrease in fair value of its historical properties in New Mexico.

General and Administrative Expense ("G&A")

G&A expenses include corporate overhead such as payroll and benefits for our corporate staff, share-based compensation expense, office rent for our headquarters, audit and other fees for professional services and legal compliance. G&A expenses are reported net of overhead recoveries.

Total G&A expense increased by $11.5 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. Administrative costs, which include payroll, benefits and non-payroll costs, increased by $8.1 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. The increase in administrative costs was primarily attributable to increased employee count, professional services, insurance, technology and office costs, which were impacted by additional needs as a result of the New Mexico Acquisition. Share-based compensation expense increased by $3.4 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. The increase in share-based compensation expense resulted from the increase in outstanding equity awards due in part to higher employee count as well as expense associated with equity awards attributable to a separation agreement with a former Company executive.

Transaction Costs

Transaction costs represent costs incurred on successful or unsuccessful business combinations or unsuccessful property acquisitions. The transaction costs of $5.8 million for the year ended December 31, 2023 relate to the New Mexico Acquisition. During the year ended December 31, 2022, the transaction costs of $2.6 million primarily related to a potential business combination and related financing that the Company pursued but ultimately chose not to consummate due to changing market conditions.

Interest Expense

Interest expense increased by $30.7 million during the year ended December 31, 2023 when compared to the year ended December 31, 2022. The increase in interest expense was primarily due to the higher debt balances as a result of financing for the New Mexico Acquisition, along with higher interest rates on borrowings under our Credit Facility for the year ended December 31, 2023 when compared to rates for the year ended December 31, 2022. Additionally, interest expense decreased during 2022 as a result of the Company settling the remaining open position on its previous interest rate swap resulting in a settlement benefit of $1.5 million.

Gain/Loss on Derivatives

The Company recognizes settlements and changes in the fair value of its derivative contracts as a single component within other income (expense) on its consolidated statements of operations. We have oil and natural gas derivative contracts, including fixed price swaps, basis swaps and collars, that settle against various indices. The following table presents the components of the Company's gain (loss) on derivatives, net for the years ended December 31, 2023 and 2022:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Settlements on derivative contracts	$ (17,221)	$ (75,257)
Non-cash gain on derivatives	23,414	23,683
Gain (loss) on derivatives, net	$ 6,193	$ (51,574)

Our earnings are affected by the changes in value of our derivative portfolio between periods and the related cash received or paid upon settlement of our derivatives. To the extent the future commodity price outlook declines between periods, we will have mark-to-market gains, while future commodity price increases between measurement periods result in mark-to-market losses.

The gain on derivatives for the year ended December 31, 2023 was $6.2 million compared to a loss on derivatives of $51.6 million for the year ended December 31, 2022. The change was primarily driven by a $58.0 million decrease in the cash payments on settlements of derivatives due to the decrease in oil and natural gas prices for the year ended December 31, 2023 compared to the year ended December 31, 2022.

Income Tax Expense

Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. See Note 11 - Income Taxes in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules for a full discussion of income taxes.

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Current income tax expense	$ 6,872	$ 4,472
Deferred income tax expense	27,589	28,372
Total income tax expense	$ 34,461	$ 32,844
Effective income tax rate	23.6 %	21.7 %

The rise in our effective income tax rate was primarily due to the New Mexico Acquisition increasing our apportionment in New Mexico, which has a higher state tax rate than where we have historically operated.

Liquidity and Capital Resources

The business of exploring for, developing and producing oil and natural gas is capital intensive. Because oil, natural gas and NGL reserves are a depleting resource, like all upstream operators, we must make capital investments to grow and even sustain production. The Company's principal liquidity requirements are to finance its operations, fund capital expenditures and acquisitions, make cash distributions and satisfy any indebtedness obligations. Cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and the significant capital expenditures required to more fully develop the Company's oil and natural gas properties. Historically, our primary sources of capital funding and liquidity have been our cash on hand, cash flow from operations, borrowings under our Credit Facility and the issuance of our Senior Notes. At times and as needed, we may also issue debt or equity securities, including through transactions under our shelf registration statement filed with the SEC. We estimate the combination of the sources of capital discussed above will continue to be adequate to meet our short and long-term liquidity needs.

Cash on hand and operating cash flow can be subject to fluctuations due to trends and uncertainties that are beyond our control. Likewise, our ability to issue equity and obtain credit facilities on favorable terms may be impacted by a variety of market factors as well as fluctuations in our results of operations. For further discussion of risks related to our liquidity and capital resources, see "Item 1A. Risk Factors."

Working Capital

Working capital is the difference in our current assets and our current liabilities. Working capital is an indication of liquidity and potential need for short-term funding. The change in our working capital requirements is driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from customers, the level and timing of spending for expansion activity, and the timing of debt maturities. As of December 31, 2023, we had a working capital deficit of $31.1 million compared to a deficit of $25.3 million as of December 31, 2022. The current portion of our Senior Notes, which includes our regularly scheduled principal payments of $5 million per quarter, accounts for $20.0 million of our working capital deficit at December 31, 2023. Additionally, increases in our revenue payable, resulting from revenue suspense associated with oil and natural gas properties acquired in the New Mexico Acquisition, contributed to the working capital deficit. Partially offsetting these higher current liabilities was an increase of $5.0 million in current derivative assets and higher accounts receivable associated with increased oil and natural gas sales. We utilize our Credit Facility and cash on hand to manage the timing of cash flows and fund short-term working capital deficits. Our current derivative assets and liabilities represent the mark-to-market value as of December 31, 2023 of future commodity production which will settle on a monthly basis through the end of their contractual terms. This aligns with the receipt of oil and natural gas revenues on a monthly basis.

Cash Flows

The following table summarizes the Company’s cash flows for the years ended December 31, 2023 and 2022:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Net cash provided by operating activities	$ 207,195	$ 170,288
Net cash used in investing activities	$ (469,556)	$ (128,256)
Net cash provided by (used in) financing activities	$ 264,379	$ (37,048)

Operating Activities

The Company’s net cash provided by operating activities increased by $36.9 million, or 22%, to $207.2 million for the year ended December 31, 2023 from $170.3 million for the year ended December 31, 2022. The increase was primarily driven by a decrease of $58.0 million in payments to settle commodity derivative contracts and an increase in revenues, partially offset by an increase in operating expenses.

Investing Activities

The Company's cash flows used in investing activities increased by $341.3 million to $469.6 million for the year ended December 31, 2023 from $128.3 million for the year ended December 31, 2022. The increase was primarily due to the $324.7 million for the New Mexico Acquisition. Investing activities also increased due to higher year-over-year capital spending for additions to oil and natural gas properties of $23.1 million, or 21%, related to the Company's increased drilling and completion activity during the year ended December 31, 2023 compared to the year ended December 31, 2022, partially attributable to the larger asset base following the New Mexico Acquisition.

Financing Activities

Net cash flow provided by financing activities increased by $301.4 million for the year ended December 31, 2023 compared to the year ended December 31, 2022. During the year ended December 31, 2023, the Company had net borrowings on its Credit Facility of $129.0 million and proceeds from issuance of its Senior Notes, net of repayments, of $173.0 million, compared to a net paydown of $9.0 million on its Credit Facility for the same period in 2022. The increase in proceeds from borrowings was primarily attributable to the New Mexico Acquisition. In addition, the Company distributed an additional $2.6 million of dividends on common stock during the year ended December 31, 2023 compared to the same period in 2022 as a result of higher outstanding share count and a higher dividend per share.

Credit Facility and Senior Notes

The Company's borrowing base on its Credit Facility was $375 million with outstanding borrowings of $185 million on December 31, 2023, representing available borrowing capacity of $190 million.

On February 22, 2023, the Company amended its Credit Facility to, among other things, allow for the issuance of unsecured Senior Notes of up to $200 million. On April 3, 2023, and concurrent with the closing of the New Mexico Acquisition, the Company entered into the fourteenth amendment to the Credit Facility to, among other things, increase the maximum facility amount to $1.0 billion and the borrowing base from $225 million to $325 million, resulting in the addition of new lenders to the lending group. On November 14, 2023, through the semi-annual redetermination, the Company increased its borrowing base to $375 million, resulting in the addition of two new lenders and the exit of one lender. The Credit Facility is set to mature in April 2026. Substantially all of the Company’s assets are pledged to secure the Credit Facility.

During the year ended December 31, 2023, the Company issued $200 million in principal amount of Senior Notes with a maturity date of April 2026. The proceeds from the Senior Notes were used to finance the New Mexico Acquisition. The principal balance of the Senior Notes as of December 31, 2023 was $185 million.

See Note 9 - Long-Term Debt in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a full discussion of our long-term debt.

Distributions

For the year ended December 31, 2023, the Company authorized and declared quarterly dividends totaling approximately $27.9 million, with $27.3 million paid in cash and $0.6 million payable to holders of restricted stock upon vesting. For the years ended December 31, 2023 and 2022, the Company paid cash dividends of approximately $0.5 million and $0.2 million, respectively, to holders of restricted stock upon vesting.

Contractual Obligations

As of December 31, 2023, the Company has commitments with its primary midstream counterparty and has purchase commitments totaling $13.1 million related to its 2024 drilling program. In addition, the Company entered into an agreement to form a joint venture and is committed to contributing its portion of capital expenditures into the joint venture company and further entered into a tolling agreement to commit to providing the natural gas needed for the joint venture. See Note 13 - Commitments and Contingencies in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a full discussion of our commitments and contingencies.

Critical Accounting Estimates

The preparation of financial statements requires the Company to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

Changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates and assumptions used in preparation of the Company's consolidated financial statements and it is at least reasonably possible these estimates could be revised in the near term and these revisions could be material.

Method of Accounting for Oil and Natural Gas Properties

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities which requires management's assessment of the proper designation of wells and associated costs as developmental or exploratory. This classification assessment is dependent on the determination and existence of proved reserves, which is a critical estimate discussed in the section below. The classification of developmental and exploratory costs has a direct impact on the amount of costs we initially recognize as exploration expense or capitalize, then subject to DD&A calculations and impairment assessments and valuations.

Once a well is drilled, the determination that proved reserves have been discovered may take considerable time and requires both judgment and application of industry experience. At the end of each quarter, the status of all suspended exploratory drilling costs are reviewed to determine whether the costs should continue to remain capitalized or shall be expensed. When making this determination, current activities, near-term plans for additional exploratory or appraisal drilling and the likelihood of reaching a development program is considered.

Similar to the evaluation of suspended exploratory well costs, costs for unproved leasehold, for which reserves have not been proven, must also be evaluated for continued capitalization or impairment. At the end of each quarter, unproved leasehold costs are assessed for impairment by considering future drilling plans, drilling activity results, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. At December 31, 2023, the Company had approximately $100.2 million of unproved leasehold. Of the remaining unproved leasehold costs at December 31, 2023, approximately $2.3 million is scheduled to expire in 2024. The Company expects to renew or extend these leases in 2024. If our drilling is not successful, this leasehold could become partially or entirely impaired.

Once a well is drilled, capitalized well costs for drilling and completion activities must be evaluated at least yearly or whenever facts and circumstances indicate a decline in the recoverability of their carrying value may have occurred. At the end of each year, the undiscounted future cash flows are compared to the carrying value on a field basis to evaluate if the carrying value is recoverable. If the carrying value is not recoverable, the Company will compare the carrying value of the asset to its fair value and recognize any impairment loss in the period. Significant inputs and judgements are used in determining the fair value of the assets. The Company utilizes a discounted cash flow model in order to estimate fair value by modeling the present value of future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with the expected cash flow projected. During the year ended December 31, 2023, the Company recognized a proved property impairment of $9.8 million relating to certain properties in Texas outside of the Company's acreage in the Champions Field. The Company recognized an impairment loss on proved properties of $7.3 million for the year ended December 31, 2022, which related to a decrease in fair value of its historical properties in New Mexico.

Oil and Natural Gas Reserves

Our estimates of proved and proved developed reserves are a major component of our depletion calculation. Additionally, our proved reserves represent the element of these calculations that require the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the timing of future expenditures. The process of estimating oil, natural gas and NGL reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data. A third-party reservoir engineering firm prepares our reserve report, which the estimates are based off of technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests.

The passage of time provides more qualitative information regarding estimates of reserves, when revisions are made to prior estimates to reflect updated information. The data for a given reservoir may also change substantially over time as a result of numerous factors, including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

Business Combinations

The Company periodically acquires assets and assumes liabilities in transactions accounted for as business combinations, such as the New Mexico Acquisition. In connection with the New Mexico Acquisition, we allocated the purchase price consideration of $324.7 million to the assets acquired and liabilities assumed based on estimated fair values as of the date of the acquisition.

We made a number of assumptions in estimating the fair value of assets acquired and liabilities assumed in the New Mexico Acquisition. The most significant assumptions relate to the estimated fair values of proved and unproved oil and gas properties. The fair value of identifiable assets acquired and liabilities assumed is determined based on various valuation techniques, including market prices, discounted cash flow analysis, and independent appraisals. Significant judgments and assumptions are inherent in these valuation techniques and include, among other things, estimates of reserves, estimates of future commodity prices, expected development costs, lease operating costs and the discount rate that reflects the risk of the underlying cash flow estimates.

Estimated fair values assigned to assets acquired can have a significant impact on future results of operations presented in the Company's financial statements. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. In the event that future commodity prices or reserve quantities are lower than those used as inputs to determine estimates of acquisition date fair values, the likelihood increases that certain costs may be determined to not be recoverable.

See Note 4 - Acquisitions of Oil and Natural Gas Properties in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a full discussion of our acquisitions.

See Note 3 - Summary of Significant Accounting Policies in the Company's consolidated financial statements in "Item 15. Exhibits and Financial Statement Schedules" for a full discussion of our significant accounting policies.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Not applicable.

Item 8. Financial Statements and Supplementary Data

The information required by this item appears beginning on page F-1 of this report.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our management establishes and maintains disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. Such information is accumulated and communicated to our management, including our Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”), as appropriate, to allow timely decisions regarding required disclosure. We evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2023, with the participation of our CEO and CFO, as well as other key members of our management. Based on this evaluation, our CEO and CFO concluded that our disclosure controls and procedures were effective as of December 31, 2023.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States.

Our management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2022, using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control - Integrated Framework* (2013). We have evaluated the effectiveness of our internal control over financial reporting as of the end of the period covered by this report, with the participation of our CEO and CFO, as well as other key members of our management. Based on this assessment, management concluded that, as of December 31, 2023, the Company’s internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2023 has been audited by BDO USA, P.C., an independent registered public accounting firm who audited our consolidated financial statements as of and for the year ended December 31, 2023, as stated in their report.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2023 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
Riley Exploration Permian, Inc.
Oklahoma City, Oklahoma

Opinion on Internal Control over Financial Reporting

We have audited Riley Exploration Permian, Inc.'s (the "Company's") internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated balance sheets of the Company as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the years then ended, and the related notes and our report dated March 6, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A, Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit of internal control over financial reporting in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ BDO USA, P.C.
Houston, Texas
March 6, 2024

Item 9B. Other Information

During the quarter ended December 31, 2023, none of our directors or officers (as defined in Rule 16a-1(f) of the Exchange Act) adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information as to Item 10 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

Item 11. Executive Compensation

Information as to Item 11 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

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

Information as to Item 12 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

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

Information as to Item 13 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

Item 14. Principal Accountant Fees and Services

Information as to Item 14 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2023.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as a part of this report:

(1) Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements appearing on page F-1.

(2) Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

(3) Exhibits

Exhibit Number	Description
2.1	Agreement and Plan of Merger, by and among Tengasco, Inc., Antman Sub, LLC, and Riley Exploration - Permian, LLC, dated as of October 21, 2020 (incorporated by reference from Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 22, 2020).
2.2	Amendment No. 1 to Agreement and Plan of Merger, by and among Tengasco, Inc., Antman Sub, LLC, and Riley Exploration - Permian, LLC, dated as of January 20, 2021 (incorporated by reference from Exhibit 2.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on January 22, 2021).
3.1	First Amended and Restated Certificate of Incorporation of Riley Exploration Permian, Inc. (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-8 filed with the Securities and Exchange Commission on March 1, 2021, Registration No. 333-253750).
3.2	Third Amended and Restated Bylaws of Riley Exploration Permian, Inc. (incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 23, 2022).
4.1*	Description of Registrant's Securities
4.2	Note Purchase Agreement, dated as of April 3, 2023, by and among Riley Exploration - Permian, LLC, as Issuer, Riley Exploration Permian, Inc., as Parent, each of the subsidiaries of the Issuer party thereto as guarantors, each of the holders from time to time party thereto, and U.S. Bank Trust Company, National Association, as agent for the holders (incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed with the Securities and Exchange Commission on April 4, 2023).
10.1	Credit Agreement dated as of September 28, 2017, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.2	First Amendment to Credit Agreement dated as of February 27, 2018, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.2 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.3	Second Amendment to Credit Agreement dated as of November 9, 2018, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.3 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.4	Third Amendment to Credit Agreement dated as of April 3, 2019, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.4 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).

10.5	Fourth Amendment to Credit Agreement dated as of October 15, 2019, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.5 to the Registrant’s Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.6	Fifth Amendment to Credit Agreement dated as of May 7, 2020, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.6 to the Registrant’s Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.7	Sixth Amendment to Credit Agreement dated as of August 31, 2020, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.7 to the Registrant’s Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.8	Seventh Amendment and Consent to Credit Agreement dated as of October 21, 2020, by and among Riley Exploration – Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.8 to the Registrant’s Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.9	Eighth Amendment to Credit Agreement dated as of March 5, 2021, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.9 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, as filed with the Securities and Exchange Commission on May 17, 2021).
10.10	Ninth Amendment to Credit Agreement dated as of May 5, 2021, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.10 to the Registrant’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2021, as filed with the Securities and Exchange Commission on May 17, 2021).
10.11	Tenth Amendment to the Credit Agreement dated as of October 12, 2021, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, as filed with the Securities and Exchange Commission on October 14, 2021).
10.12	Form of Indemnity Agreement (incorporated by reference from Exhibit 10.14 to the Registrant’s Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on January 21, 2021, Registration No. 333-250019).
10.13	Form of Independent Director Agreement (incorporated by reference from Exhibit 10.13 to the Registrant’s Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on January 21, 2021, Registration No. 333-250019).
10.14†	Form of Substitute Restricted Stock Agreement (Time Vesting) (incorporated by reference from Exhibit 4.5 to the Registrant’s Registration Statement on Form S-8 filed with the Commission on March 1, 2021, Registration No. 333-253750).
10.15†	Form of Restricted Stock Agreement (Non-Employee Director) (incorporated by reference from Exhibit 4.6 to the Registrant’s Registration Statement on Form S-8 filed with the Commission on March 1, 2021, Registration No. 333-253750).
10.16†	Employment Agreement dated effective as of March 15, 2021 by and between Riley Exploration Permian, Inc. and Corey Riley (incorporated by reference from Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.17†	Employment Agreement dated effective as of March 15, 2021 by and between Riley Exploration Permian, Inc. and Philip Riley (incorporated by reference from Exhibit 10.2 to the Registrant’s Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.18†	Employment Agreement dated April 1, 2019 by and between Riley Exploration – Permian, LLC and Bobby D. Riley and assigned by Riley Exploration – Permian, LLC to Riley Permian Operating Company, LLC on June 8, 2019 (incorporated by reference from Exhibit 10.9 to the Registrant’s Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).

10.19†	Amendment No. 1 to Employment Agreement dated October 1, 2020 by and between Riley Permian Operating Company, LLC and Bobby D. Riley (incorporated by reference from Exhibit 10.10 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.20†	Amendment No. 2 to Employment Agreement dated March 15, 2021 by and between Riley Permian Operating Company, LLC and Bobby D. Riley (incorporated by reference from Exhibit 10.7 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.21†	Employment Agreement dated April 1, 2019 by and between Riley Exploration – Permian, LLC and Kevin Riley and assigned by Riley Exploration – Permian, LLC to Riley Permian Operating Company, LLC on June 8, 2019 (incorporated by reference from Exhibit 10.11 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019)
10.22†	Amendment No. 1 to Employment Agreement dated March 15, 2021 by and between Riley Permian Operating Company, LLC and Kevin Riley (incorporated by reference from Exhibit 10.8 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on March 15, 2021).
10.23	Second Amended and Restated Registration Rights Agreement dated October 7, 2020 by and among Riley Exploration – Permian, LLC, Riley Exploration Group, Inc., Yorktown Energy Partners XI, L.P., Boomer Petroleum, LLC, Bluescape Riley Exploration Holdings LLC, Bluescape Riley Acquisition Company LLC, Bobby D. Riley, Kevin Riley and Corey Riley (incorporated by reference to Exhibit 4.1 to the Registrant's Registration Statement on Form S-4/A, as filed with the Securities and Exchange Commission on December 31, 2020, Registration No. 333-250019).
10.24†	Employment Agreement dated effective as of January 25, 2022 by and between Riley Exploration Permian, Inc. and Amber Bonney (incorporated by reference from Exhibit 10.2 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on January 27, 2022).
10.25	Eleventh Amendment to the Credit Agreement dated as of April 29, 2022, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on May 2, 2022).
10.26	Twelfth Amendment to the Credit Agreement dated as of October 25, 2022, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on October 26, 2022).
10.27	Thirteenth Amendment to the Credit Agreement dated as of February 22, 2023, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.2 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on February 27, 2023).
10.28	Purchase and Sale Agreement dated February 22, 2023 by and between Pecos Oil & Gas, LLC, as Seller, and Riley Exploration - Permian, LLC, as Purchaser (incorporated by reference from Exhibit 2.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on February 27, 2023).
10.29	Commitment Letter dated February 22, 2023 by and between Riley Exploration Permian, Inc. and EOC Partners Advisors L.P. (incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on February 27, 2023)
10.30	Fourteenth Amendment to the Credit Agreement dated as of April 3, 2023, by and among Riley Exploration Permian, Inc., Riley Exploration - Permian, LLC, as borrower, Truist Bank, as administrative agent, and the lenders party thereto (incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on April 4, 2023).
10.31†	Riley Exploration Permian, Inc. 2021 Long Term Incentive Plan, as amended and restated as of April 21, 2023 (Incorporated by reference from Exhibit 10.1 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on April 24, 2023).
10.32†	Form of Restricted Stock Agreement (Time Vesting - Named Executive Officers), as amended and restated as of April 21, 2023 (Incorporated by reference from Exhibit 10.2 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on April 24, 2023).

10.33†	Form of Restricted Stock Agreement (Non-Employee Director), as amended and restated as of April 21, 2023 (Incorporated by reference from Exhibit 10.3 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on April 24, 2023).
10.34†	Form of Common Stock Award Agreement, as amended and restated as of April 21, 2023 (Incorporated by reference from Exhibit 10.4 to the Registrant's Current Report on Form 8-K, as filed with the Securities and Exchange Commission on April 24, 2023).
10.35†	Separation and Release Agreement dated December 21, 2023, by and among Riley Exploration Permian, Inc., Riley Permian Operating Company, LLC, and Kevin Riley (Incorporated by reference from Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, as filed with the Securities and Exchange Commission on December 26, 2023).
21.1*	Subsidiaries of the Registrant
23.1*	Consent of BDO USA, P.C.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C., Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C., Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
97.1*	Riley Exploration Permian, Inc. Clawback Policy Effective December 1, 2023
99.1*	Report of Ryder Scott Company, L.P.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Definition Linkbase Document
101.LAB*	XBRL Taxonomy Label Linkbase Document
101.PRE*	XBRL Taxonomy Presentation Linkbase Document

* Filed herewith.

† Compensatory plan or 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 hereunto duly authorized.

RILEY EXPLORATION PERMIAN, INC.

Date: March 6, 2024

By: /s/ Bobby D. Riley
Bobby D. Riley
Chief Executive Officer and President

By: /s/ Philip Riley
Philip Riley
Chief Financial Officer and Executive Vice President of Strategy

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

Signature	Title	Date
/s/ Bobby D. Riley Bobby D. Riley	Chairman of the Board, Chief Executive Officer and President (Principal Executive Officer)	March 6, 2024
/s/ Philip Riley Philip Riley	Chief Financial Officer and Executive Vice President of Strategy (Principal Financial Officer)	March 6, 2024
/s/ Amber Bonney Amber Bonney	Chief Accounting Officer (Principal Accounting Officer)	March 6, 2024
/s/ Brent Arriaga Brent Arriaga	Director	March 6, 2024
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director	March 6, 2024
/s/ E. Wayne Nordberg E. Wayne Nordberg	Director	March 6, 2024
/s/ Beth A. di Santo Beth A di Santo	Director	March 6, 2024
/s/ Rebecca Bayless Rebecca Bayless	Director	March 6, 2024

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
Riley Exploration Permian, Inc.
Oklahoma City, Oklahoma

Opinion on the consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Riley Exploration Permian, Inc. (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at December 31, 2023 and 2022, and the results of its operations and its cash flows for the years then ended**,** in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and our report dated March 6, 2024 expressed an unqualified opinion thereon.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the 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 consolidated financial statements are free of material misstatement, whether due to error or fraud.

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Estimation of Future Production Volumes Used to Estimate Proved Oil and Natural Gas Reserves and the Associated Effect on Depreciation, Depletion and Amortization ("DD&A") Expense Related to Proved Oil and Natural Gas Properties

As described in Note 3 to the consolidated financial statements, the Company uses the successful efforts method of accounting for its oil and natural gas producing activities which involves management making significant estimates including forecasting of future production volumes of proved oil and natural gas reserves. As disclosed in Note 5, the Company's oil and natural gas properties, net balance as of December 31, 2023 was $846.9 million, which includes proved oil and natural gas properties of $895.7 million and accumulated depletion, amortization and impairment of $206.1 million. DD&A expense was $62.5 million for the year ended December 31, 2023.

We have identified the estimation of future production volumes used to estimate proved oil and natural gas reserves and the associated effect on DD&A expense related to proved oil and natural gas properties as a critical audit matter. Estimating future production volumes involves a high degree of subjectivity from management and their internal and independent petroleum engineers. Changes in this estimate could have a significant effect on the measurement of DD&A expense. Auditing this estimate required subjective and complex auditor judgement.

The primary procedures we performed to address this critical audit matter included:

- Evaluating the professional qualifications and objectivity of the internal and independent petroleum engineers, including their relationship to the Company.

- Comparing estimates of future production volumes against historical results of production volumes on a summary basis for all wells and on a detailed basis for certain wells.

- Performing a retrospective review over management estimates of future production volumes made in prior periods as compared to actual results.

Estimation of Future Production Volumes Used to Estimate Fair Value of The Acquired Oil & Natural Gas Properties in the New Mexico Acquisition

As described in Note 4 to the consolidated financial statements, the Company completed the New Mexico Acquisition from Pecos for approximately $330 million, before customary purchase price adjustments. The transaction qualified as a business combination under ASC 805, Business Combinations, and as such, all assets and liabilities associated with the New Mexico Acquisition were recognized at fair value as of the acquisition date. As a result of the New Mexico Acquisition, the Company recognized oil and natural gas properties of $342.3 million, which are included in oil and natural gas properties, net within the Company's consolidated balance sheet. To determine the acquisition date fair value of the oil and natural gas properties, management made significant estimates including forecasting of future production volumes of the acquired oil and natural gas properties.

We have identified the estimation of future production volumes used to estimate the acquisition date fair value of the acquired oil and natural gas properties in the New Mexico Acquisition as a critical audit matter. Estimating future production volumes involves a high degree of subjectivity from management and their internal and independent petroleum engineers. Changes in this estimate could have a significant effect on the acquisition date fair value of the acquired oil and natural gas properties. Auditing this estimate required subjective and complex auditor judgement.

The primary procedures we performed to address this critical audit matter included:

- Evaluating the professional qualifications and objectivity of the internal and independent petroleum engineers, including their relationship to the Company.

- Comparing estimates of future production volumes against historical results of production volumes on a summary basis for all acquired wells and on a detailed basis for certain wells.

- Performing a retrospective review over management estimates of future production volumes made in the acquisition date fair value forecast as compared to actual results.

/s/ BDO USA, P.C.

We have served as the Company's auditor since 2016.

Houston, Texas
March 6, 2024

RILEY EXPLORATION PERMIAN, INC.

CONSOLIDATED BALANCE SHEETS

	December 31, 2023	December 31, 2022
	(In thousands, except share amounts)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 15,319	$ 13,301
Accounts receivable	35,126	25,551
Prepaid expenses	1,625	3,236
Inventory	6,177	8,886
Current derivative assets	5,013	20
Total current assets	**63,260**	**50,994**
Oil and natural gas properties, net (successful efforts)	846,901	440,102
Other property and equipment, net	20,653	20,023
Non-current derivative assets	2,296	—
Other non-current assets, net	12,601	4,175
Total Assets	**$ 945,711**	**$ 515,294**
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable	$ 3,855	$ 3,939
Accrued liabilities	33,159	35,582
Revenue payable	30,695	17,750
Current derivative liabilities	360	16,472
Current portion of long-term debt	20,000	—
Other current liabilities	6,276	2,562
Total Current Liabilities	**94,345**	**76,305**
Non-current derivative liabilities	—	12
Asset retirement obligations	19,255	2,724
Long-term debt	335,959	56,000
Deferred tax liabilities	73,345	45,756
Other non-current liabilities	1,212	1,051
Total Liabilities	**524,116**	**181,848**
Commitments and Contingencies (Note 13)		
Shareholders' Equity:		
Preferred stock, $ 0.0001 par value, 25,000,000 shares authorized; 0 shares issued and outstanding	—	—
Common stock, $ 0.001 par value, 240,000,000 shares authorized; 20,405,093 and 20,160,980 shares issued and outstanding at December 31, 2023 and December 31, 2022, respectively	20	20
Additional paid-in capital	279,112	274,643
Retained earnings	142,463	58,783
Total Shareholders' Equity	**421,595**	**333,446**
Total Liabilities and Shareholders' Equity	**$ 945,711**	**$ 515,294**

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

RILEY EXPLORATION PERMIAN, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,	
	2023	2022
	(In thousands, except per share amounts)	
Revenues:		
Oil and natural gas sales, net	$ 372,647	$ 319,343
Contract services - related parties	2,400	2,400
Total Revenues	**375,047**	**321,743**
Costs and Expenses:		
Lease operating expenses	58,817	32,458
Production and ad valorem taxes	25,559	19,273
Exploration costs	4,165	2,032
Depletion, depreciation, amortization and accretion	65,055	32,113
Impairment of oil and natural gas properties	9,760	7,325
General and administrative:		
Administrative costs	26,569	18,496
Share-based compensation expense	6,833	3,439
Cost of contract services - related parties	579	450
Transaction costs	5,817	2,638
Total Costs and Expenses	**203,154**	**118,224**
Income From Operations	**171,893**	**203,519**
Other Income (Expense):		
Interest expense, net	(31,816)	(1,090)
Gain (loss) on derivatives, net	6,193	(51,574)
Loss from equity method investment	(218)	—
Total Other Income (Expense)	**(25,841)**	**(52,664)**
Net Income From Operations Before Income Taxes	**146,052**	**150,855**
Income tax expense	(34,461)	(32,844)
Net Income	**$ 111,591**	**$ 118,011**
Net Income per Share:		
Basic	$ 5.66	$ 6.04
Diluted	$ 5.58	$ 5.99
Weighted Average Common Shares Outstanding:		
Basic	19,705	19,553
Diluted	20,000	19,686

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

RILEY EXPLORATION PERMIAN, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(In Thousands)

	Shareholders' Equity				
	Common Stock				
	Shares	Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Shareholders' Equity
Balance, December 31, 2021	**19,837**	**$ 20**	**$ 271,737**	**$ (33,919)**	**$ 237,838**
Share-based compensation expense	369	—	3,946	—	3,946
Repurchased shares for tax withholding	(45)	—	(1,040)	—	(1,040)
Dividends declared	—	—	—	(25,309)	(25,309)
Net income	—	—	—	118,011	118,011
Balance, December 31, 2022	**20,161**	**$ 20**	**$ 274,643**	**$ 58,783**	**$ 333,446**
Share-based compensation expense	315	—	6,978	—	6,978
Repurchased shares for tax withholding	(80)	—	(2,511)	—	(2,511)
Issuance of common shares under ATM	9	—	2	—	2
Dividends declared	—	—	—	(27,911)	(27,911)
Net income	—	—	—	111,591	111,591
Balance, December 31, 2023	**20,405**	**$ 20**	**$ 279,112**	**$ 142,463**	**$ 421,595**

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

RILEY EXPLORATION PERMIAN, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Cash Flows from Operating Activities:		
Net income	$ 111,591	$ 118,011
Adjustments to reconcile net income to net cash provided by operating activities:		
Exploratory well costs and lease expirations	4,143	1,953
Depletion, depreciation, amortization and accretion	65,055	32,113
Impairment of proved properties	9,760	7,325
(Gain) loss on derivatives, net	(6,193)	51,574
Settlements on derivative contracts	(17,221)	(75,257)
Amortization of deferred financing costs and discount	4,161	731
Share-based compensation expense	6,978	3,946
Deferred income tax expense	27,589	28,372
Other	193	—
Changes in operating assets and liabilities		
Accounts receivable	(9,575)	(7,549)
Prepaid expenses and other current assets	(717)	5,250
Inventory	(546)	(6,235)
Other non-current assets	(1,179)	(12)
Accounts payable and accrued liabilities	3,200	2,860
Revenue payable	11,470	6,380
Other current liabilities	(1,514)	826
Net Cash Provided by Operating Activities	**207,195**	**170,288**
Cash Flows from Investing Activities:		
Additions to oil and natural gas properties	(134,796)	(111,662)
Net assets acquired in business combination	(324,686)	—
Acquisitions of oil and natural gas properties	(5,443)	—
Acquisitions of land	—	(15,342)
Contributions to equity method investment	(3,566)	—
Additions to other property and equipment	(1,065)	(1,252)
Net Cash Used in Investing Activities	**(469,556)**	**(128,256)**
Cash Flows from Financing Activities:		
Deferred financing costs	(7,406)	(1,942)
Proceeds from credit facility	185,000	22,000
Repayments under credit facility	(56,000)	(31,000)
Proceeds from senior notes, net of issuance costs	188,000	—
Repayments of senior notes	(15,000)	—
Payment of common share dividends	(27,706)	(25,066)
Other	2	—
Common stock repurchased for tax withholding	(2,511)	(1,040)
Net Cash Provided by (Used in) Financing Activities	**264,379**	**(37,048)**
Net Increase in Cash and Cash Equivalents	**2,018**	**4,984**
Cash and Cash Equivalents, Beginning of Year	**13,301**	**8,317**
Cash and Cash Equivalents, End of Year	**$ 15,319**	**$ 13,301**

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

RILEY EXPLORATION PERMIAN, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS - (Continued)

(Unaudited)

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Supplemental Disclosure of Cash Flow Information		
Cash Paid For:		
Interest, net of capitalized interest	$ 27,140	$ 1,749
Income taxes	$ 9,949	$ 3,611
Non-cash Investing and Financing Activities:		
Changes in capital expenditures in accounts payable and accrued liabilities	$ (5,850)	$ 15,229
Right of use assets obtained in exchange for operating lease liability	$ 1,277	$ 1,655
Assets contributed to equity method investment	$ 2,272	$ —
Asset retirement obligations assumed in acquisitions	$ 19,359	$ —

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

RILEY EXPLORATION PERMIAN, INC.
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(1) Nature of Business

Organization

Riley Exploration Permian, Inc (the "Company") was formed as a Delaware limited liability company, Riley Exploration – Permian, LLC ("REP LLC"), in 2016. In February 2021, REP LLC consummated a merger pursuant to which REP LLC became a wholly-owned subsidiary of Tengasco, Inc., a Delaware corporation (“Tengasco”), and Tengasco changed its name to Riley Exploration Permian, Inc. (the "Merger"). The Company is a growth-oriented, independent oil and natural gas company focused on the acquisition, exploration, development and production of oil, natural gas and NGLs in Texas and New Mexico.

On April 3, 2023 (the “Closing Date”), the Company completed the acquisition of oil and natural gas assets (the “New Mexico Acquisition”) from Pecos Oil & Gas, LLC (“Pecos”), a Delaware limited liability company and an affiliate of Cibolo Energy Partners LLC. For further information regarding the New Mexico Acquisition, see Note 4 - Acquisitions of Oil and Natural Gas Properties.

Our Properties

Our acreage is primarily located on large contiguous blocks in Yoakum County, Texas, which represents our Champions Field and Eddy County, New Mexico, which represents our Redlake Field acquired in the New Mexico Acquisition. Our activities primarily include the horizontal development of conventional reservoirs on the Northwest Shelf of the Permian Basin. Our acreage is primarily located on large, contiguous blocks in Yoakum County, Texas and Eddy County, New Mexico.

Current Commodity Environment

The U.S. and global economies and markets have experienced heightened volatility following impactful geopolitical events, the effects of widespread inflation and the impact of significantly higher interest rates. Prices for oil and natural gas are determined primarily by prevailing market conditions, which have been and could continue to be volatile.

The combination of geopolitical events, inflation and the rising interest rate environment has led to increasing forecasts of a U.S. or global recession. Any such recession could prolong market volatility or cause a decline in commodity prices, among other potential impacts.

The Company cannot estimate the length or gravity of the future impact these events will have on the Company's results of operations, financial position, liquidity and the value of oil and natural gas reserves.

(2) Basis of Presentation

Effective by the Company's Board of Directors written consent on September 23, 2022, the Company's fiscal year is now the period from January 1 to December 31, beginning with the year ended December 31, 2022.

The Company's accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States ("U.S. GAAP"). All intercompany balances and transactions have been eliminated upon consolidation.

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had no effect on the previously reported total assets, total liabilities, shareholders' equity, results of operations or cash flows .

(3) Summary of Significant Accounting Policies

Significant Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Actual results may differ significantly from the Company’s estimates. Any effects on the Company’s business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include, but are not limited to, estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, accounts receivable, accrued capital expenditures and operating expenses, asset retirement obligations ("ARO"), the fair value determination of acquired assets and assumed liabilities, certain tax accruals and the fair value of derivatives.

Cash and Cash Equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. The Company maintains cash at financial institutions which may at times exceed federally insured amounts. The Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on its cash and cash equivalents.

Accounts Receivable

Our receivables arise primarily from the sale of oil, natural gas and natural gas liquids ("NGLs") and joint interest owner receivables for properties in which we serve as the operator. Accounts receivable are stated at amounts due, net of an allowance for credit losses, if necessary.

Accounts receivable from oil, natural gas and NGL sales are generally due within 30 to 60 days after the last day of each production month. No interest is charged on past-due balances. Payments made on all accounts receivable are applied to the earliest unpaid items.

To the extent actual volumes and prices of oil, natural gas and NGLs are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volume and prices for these properties are estimated and recorded within accounts receivable in the accompanying consolidated balance sheets. Oil is priced based upon prevailing prices published by purchasers with certain adjustments related to oil quality and physical location. Natural gas pricing provisions are tied to a market index, with certain adjustments based on, among other factors, quality and heat content of natural gas, and prevailing supply and demand conditions. NGLs are priced based upon a market index with certain adjustments for transportation and fractionation. These market indices are determined on a monthly basis.

The Company estimates uncollectible amounts based on the length of time that the accounts receivable has been outstanding, historical collection experience and current and future economic and market conditions, if failure to collect is expected to occur. Allowances for credit losses are recorded as reductions to the carrying values of the accounts receivables included in the Company’s consolidated balance sheets and are recorded in Administrative costs in the consolidated statements of operations if failure to collect an estimable portion is determined to be probable. The Company had no allowance for credit losses at December 31, 2023 and 2022.

Accounts receivable is summarized below:

	December 31,	
	2023	2022
	(In thousands)	
Oil, natural gas and NGL sales	$ 31,135	$ 24,136
Joint interest accounts receivable	1,630	793
Other accounts receivable	2,361	622
Total accounts receivable	$ 35,126	$ 25,551

As of December 31, 2021, the Company had accounts receivables from oil, natural gas and NGL sales of $ 17.6 million.

Inventory

The Company's inventory represents tangible assets such as drilling pipe, tubing, casing and operating supplies used in the Company's future drilling or repair operations. The Company accounts for its inventory using the first-in, first-out method and valued at the lower of cost or net realizable value.

Proved Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for its oil and natural gas producing activities. Under this method, all property acquisition costs and costs of development wells are capitalized as incurred. The costs of development wells are capitalized whether producing or non-producing. Costs to drill exploratory wells are capitalized, or suspended, pending the determination of whether proved reserves are found. If an exploratory well is determined to be unsuccessful, the costs of drilling the unsuccessful exploratory well are charged to exploration costs.

Geological and geophysical costs, including seismic studies, are charged to exploration costs as incurred. Expenditures incurred to operate and for maintenance, repairs and minor renewals necessary to maintain the oil and natural gas properties in operating condition are charged to lease operating expenses as incurred.

Capitalized costs of proved oil and natural gas properties are amortized using the units-of-production method based on production and estimates of proved reserve quantities. Leasehold acquisition costs of proved properties are depleted over total estimated proved reserves, and capitalized development costs of wells and related equipment and facilities are depleted over-estimated proved developed reserves.

On the sale or retirement of a complete unit of a proved property or field, the cost and related accumulated depletion, depreciation and amortization are eliminated from the oil and natural gas property accounts, and the resulting gain or loss is recognized. On the sale of a partial unit of proved property, the unamortized cost of the property is apportioned to the interest sold and the interest retained is accounted for on the basis of the fair value of the retained interests and a gain or loss is recognized if the divestiture significantly affects the depletion rate.

Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties consist of costs incurred to acquire unproved leases. Unproved lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we charge the associated unproved lease acquisition costs to exploration costs. Lease acquisition costs related to successful drilling are reclassified to proved oil and natural gas properties.

Upon the sale of an entire interest in an unproved property for cash or cash equivalents, a gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from the sale of partial interests in unproved oil and natural gas properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Impairment of Oil and Natural Gas Properties

The cost of proved oil and natural gas properties are assessed on a field-by-field basis for impairment at least annually or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The expected undiscounted future cash flows of the oil and natural gas properties are compared to the carrying amount of the oil, natural gas and NGL properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the oil and natural gas properties is adjusted to estimated fair value. Assumptions associated with discounted cash flow models or valuations used in the impairment evaluation include estimates of future oil, natural gas and NGL prices, production costs, development expenditures, anticipated production of proved reserves, appropriate risk-adjusted discount rates and other relevant data. Unproved oil and natural gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage. See further discussion in Note 7 - Fair Value Measurements.

Business Combinations

The Company accounts for business combinations in accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 805, Business Combinations. The Company accounts for its acquisitions that qualify as a business using the acquisition method in which the Company recognizes and measures identifiable assets acquired, liabilities assumed, and any non-controlling interest in the acquired entity at their fair values as of the acquisition date. If the set of assets and activities acquired is not considered a business, it is accounted for as an asset acquisition using a cost accumulation model. In the cost accumulation model, the cost of the acquisition, including certain transaction costs, is allocated to the assets acquired on the basis of relative fair values.

The Company includes the results of operations of acquired businesses beginning on the respective acquisition dates. In accordance with the acquisition method, the Company allocates the purchase price of an acquired business to its identifiable assets and liabilities based on the estimated fair values. The fair values of identifiable assets acquired and liabilities assumed are determined based on various valuation techniques, including market prices, discounted cash flow analysis, and independent appraisals. This fair value measurement is based on unobservable (Level 3) inputs. The excess of the purchase price over the amount allocated to the assets and liabilities, if any, is recorded as goodwill. The excess value of the net identifiable assets and liabilities acquired over the purchase price of an acquired business, if any, is recorded as a bargain purchase gain. Transaction costs related to the business combination are expensed as incurred.

Other Property and Equipment, Net

Property and equipment are capitalized and recorded at cost, while maintenance and repairs are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 5 to 39 years. Capitalized costs related to leasehold improvements are depreciated over the life of the lease. As of December 31, 2023 and 2022, the Company had capitalized property and equipment costs of $ 6.6 million and $ 5.3 million, respectively, with $ 2.6 million and $ 2.0 million, respectively, of accumulated depreciation on the consolidated balance sheets. Components of other property and equipment consists of computer equipment, office furniture, tools and equipment, buildings and improvements, and vehicles.

Land purchases are accounted for at cost and are not depreciated. As of both December 31, 2023 and 2022, the Company had capitalized land costs of $ 16.7 million on the consolidated balance sheets.

Deferred Financing Costs

Deferred financing costs include origination, arrangement, legal and other fees to issue or amend the terms of the revolving credit facility ("Credit Facility") and unsecured senior notes ("Senior Notes"). In the consolidated balance sheets, unamortized deferred financing costs related to the Credit Facility are reported as other non-current assets. For the Senior Notes, such costs are netted against the carrying value of the Senior Notes. Deferred financing costs are recognized on the consolidated statement of operations as interest expense by amortizing the costs over the related financing using the straight-line method, which approximates the effective interest method.

Equity Issuance Costs

Equity issuance costs include underwriter, legal, accounting, printing and other fees to issue common equity securities. These issuance costs are netted against offering proceeds at the time of issuance and are reported as additional paid in capital when related to the issuance of common equity securities. The issuance costs are expensed to the consolidated statement of operations if the issuance is unsuccessful.

Other Non-Current Assets, Net

Other non-current assets consisted of the following:

	December 31,	
	2023	2022
	(In thousands)	
Deferred financing costs, net	$ 3,844	$ 2,556
Right of use assets	1,890	1,370
Equity method investment	5,620	—
Other	1,247	249
Total other non-current assets, net	$ 12,601	$ 4,175

The Company incurred $ 2.8 million in financing costs related to the amendments of the Credit Facility in 2023. The Company extended certain existing office leases and entered into new vehicle leases during the year ended December 31, 2023, which resulted in additions to the right of use assets.

Equity method investment. In January 2023, the Company entered into an agreement to form a joint venture created for the purpose of constructing a new power infrastructure for onsite power generation in Yoakum County, Texas using produced natural gas. RPC Power Holdco LLC, a wholly-owned subsidiary of REPX, has a 30 % investment in the joint venture, RPC Power LLC ("RPC Power"). The Company contributed its portion of capital for construction of the onsite power generation. As of December 31, 2023, the Company had invested $ 5.8 million to date in the joint venture, comprised of $ 3.6 million in cash and $ 2.3 million of contributed assets, which was reduced by the Company's share of the joint venture's loss during the year ended December 31, 2023.

The Company accounts for its corporate joint ventures under the equity method of accounting in accordance with FASB ASC Topic 323 “Investments — Equity Method and Joint Ventures.” The Company applies the equity method of accounting to investments of less than 50% in an investee over which the Company exercises significant influence but does not have control. Under the equity method of accounting, the Company’s share of the investee’s earnings or loss is recognized in the consolidated statements of operations.

Judgment regarding the level of influence over each equity method investment includes considering key factors such as ownership interest, representation on the board of directors, participation in policy-making decisions, material intercompany transactions and extent of ownership by an investor in relation to the concentration of other shareholdings.

Accrued Liabilities

Accrued liabilities consisted of the following:

	December 31,	
	2023	2022
	(In thousands)	
Accrued capital expenditures	$ 15,851	$ 16,744
Accrued lease operating expenses	6,038	4,607
Accrued general and administrative costs	4,655	2,286
Accrued inventory	—	6,235
Accrued ad valorem tax	5,269	3,789
Other accrued expenditures	1,346	1,921
Total accrued liabilities	$ 33,159	$ 35,582

Asset Retirement Obligations

ARO consist of future plugging and abandonment expenses on oil and natural gas properties. The fair value of ARO is recorded as a liability in the period in which wells are drilled with a corresponding increase in the carrying amount of oil and natural gas properties. The liability is accreted for the change in its present value each period and the capitalized cost is depreciated using the units-of-production method. The asset and liability are adjusted for changes resulting from revisions to the timing or the amount of the original estimate when deemed necessary. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Components of the changes in ARO consisted of the following and is shown below:

	December 31,	
	2023	2022
	(In thousands)	
ARO, beginning balance	$ 3,038	$ 2,453
Liabilities incurred	45	358
Liabilities assumed in acquisitions[1]	19,359	—
Revision of estimated obligations	—	326
Liability settlements and disposals	(1,039)	(178)
Accretion	1,641	79
ARO, ending balance	23,044	3,038
Less: current ARO[2]	(3,789)	(314)
ARO, long-term	$ 19,255	$ 2,724

(1) Primarily relates to ARO assumed in the New Mexico Acquisition.

(2) Current ARO is included within other current liabilities on the accompanying consolidated balance sheets.

Revenue Recognition

Oil Sales

Under the Company’s oil sales contracts, oil that is produced by the Company is delivered to the purchaser at a contractually agreed-upon delivery point at which point the purchaser takes custody, title and risk of loss of the product. Once control has been transferred, the purchaser transports the product to a third party and receives market-based prices from the third party. The Company receives a percentage of proceeds received by the purchaser less transportation costs in accordance with the pricing provisions in the Company's contracts. As transportation costs are incurred after the transfer of control, the costs are included in oil and natural gas sales and represent part of the transaction price of the contract. The pricing provisions also provide quantity requirements and grade and quality specifications. The Company recognizes revenue at the net price received when control transfers to the purchaser.

Natural Gas and NGL Sales

Under the Company’s natural gas gathering and processing contracts, natural gas is delivered to the purchaser at the inlet of the purchasers' gathering system, at which point title and risk of loss is transferred to the purchaser. The purchaser gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of natural gas and NGLs in accordance with the pricing provisions of the Company's contracts. As the gathering, processing and transportation activities occur after the transfer of control, these costs are netted against our oil and natural gas sales and represent part of the transaction price of the contract, and may exceed the sales price. The pricing provisions also provide quantity requirements and grade and quality specifications. The Company recognizes revenue on a net basis for amounts expected to be received from third party customers through the marketing process.

Transaction Price Allocated to Remaining Performance Obligations

Based on the Company’s current product sales contracts, with contract terms ranging from one to ten years , each unit of production is considered a separate performance obligation and therefore future production volumes are wholly unsatisfied and do not require allocation or disclosure of the transaction price to remaining performance obligations.

Contract Balances

Under the Company’s product sales contracts, the Company has the right to invoice customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company’s product sales contracts do not give rise to contract assets or liabilities under ASC 606.

Prior-Period Performance Obligations

Revenue is recorded in the month in which production is delivered to the purchaser. However, certain settlement statements for oil, natural gas and NGLs may not be received for thirty to ninety days after the date production is delivered and, as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. Differences identified between the Company’s revenue estimates and actual revenue received historically have not been significant. For the years ended December 31, 2023 and 2022, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Disaggregation of Revenue

The following table presents oil and natural gas sales disaggregated by product:

	Year Ended December 31,	
	2023	**2022**
	(In thousands)	
Oil and natural gas sales:		
Oil	$ 363,125	$ 298,723
Natural gas	2,612	10,755
NGLs	6,910	9,865
Total oil and natural gas sales, net	$ 372,647	$ 319,343

Contract Services with Related Parties

The Company has contracts with related parties to provide certain contract operating, accounting and back-office support services. Revenue related to these contract services is recognized over time as the services are rendered, and the fee is stated within the contract at a fixed monthly rate. Costs directly attributable to performing these services are also recognized as the services are rendered. Refer to Note 8 - Transactions with Related Parties for a more detailed discussion regarding these contracts.

Revenue Payable

For certain oil and natural gas properties, where the Company serves as operator, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds that the Company has not yet distributed to other revenue and royalty owners are reflected as revenue payable in the consolidated balance sheets.

Lease Operating Expenses

Lease operating costs, including payroll for field personnel, saltwater disposal, electricity, generator rentals, diesel fuel and other operating expenses, are expensed as incurred and included in lease operating expenses in our consolidated statements of operations.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes, which requires the establishment of deferred tax accounts for all temporary differences between: (i) financial reporting and tax bases of assets and liabilities, using currently enacted federal and state income tax rates, and (ii) operating loss and tax credit carryforwards. In addition, deferred tax accounts must be adjusted to reflect new rates if enacted into law.

Realization of deferred tax assets is contingent on the generation of future taxable income. As a result, management considers whether it is more likely than not that all or a portion of such assets will be realized during periods when they are available, and if not, management provides a valuation allowance for amounts not likely to be recognized.

Management periodically evaluates tax reporting methods to determine if any uncertain tax positions exist that would require the establishment of a loss contingency. A loss contingency would be recognized if it were probable that a liability has been incurred as of the date of the financial statements and the amount of the loss can be reasonably estimated. The amount recognized is subject to estimates and management’s judgment with respect to the likely outcome of each uncertain tax position. The amount that is ultimately incurred for an individual uncertain tax position or for all uncertain tax positions in the aggregate could differ from the amount recognized. Interest and penalties, if any, related to uncertain tax positions are included in current income tax expense. There are no unrecorded liabilities for uncertain tax positions related to the Company as of December 31, 2023 and 2022. See further discussion in Note 11- Income Taxes.

Interest Expense

We have financed a portion of our working capital requirements, capital expenditures and certain acquisitions with borrowings under our Credit Facility as well as the issuance of Senior Notes. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. Interest expense in the consolidated statements of operations reflects interest, unused commitment fees paid to our lender, interest rate swap settlements and the amortization of deferred financing costs (including origination and amendment fees) less amounts allocated to capital expenditures. Interest expense was $ 31.8 million and $ 1.1 million for the years ended December 31, 2023 and 2022, respectively.

Capitalized interest represents interest expense related to wells in process during the period in which the Company is incurring costs and expending resources to get the properties ready for their intended purpose. Capitalized interest is added to the cost of the underlying asset and is amortized over the useful life of the asset in the same manner as the underlying asset.

Concentrations of Credit Risk

Our customer concentration may impact our overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions affecting the oil and natural gas industry.

We sell our production at market prices and to a relatively small number of purchasers, as is customary in the exploration, development and production business. Our purchaser contracts include marketing provisions with our purchasers to market our production. For the years ended December 31, 2023 and 2022, one purchaser accounted for 70 % and 89 %, respectively, of our revenue purchased. For the year ended December 31, 2023, one other purchaser accounted for 10% or more of our revenues. During the year ended December 31, 2022, no other purchaser accounted for 10% or more of our revenues. The loss of either of these purchasers could materially and adversely affect our revenues in the short-term. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any of our purchasers would not have a long-term material adverse effect on our financial condition and results of operations because oil and natural gas are fungible products with well-established markets.

Our primary exposure to credit risk is through receivables from the sale of our oil, natural gas, and NGLs (approximately $ 31.1 million at December 31, 2023) and the collection of receivables from joint interest owners for their proportionate share of expenditures made on properties in which we serve as the operator (approximately $ 1.6 million at December 31, 2023).

We manage credit risk related to accounts receivable through netting revenues and expenses on properties in which we serve as the operator, credit approvals, escrow accounts and monitoring procedures. Accounts receivable are generally not collateralized. However, we routinely assess the financial strength of our customers and counterparties and, based upon factors surrounding the credit risk, establish an allowance for uncollectible accounts, if required. As a result, we believe that our accounts receivable credit risk exposure beyond such allowance is limited.

Environmental and Other Issues

We are engaged in oil and natural gas exploration and production and may become subject to certain liabilities as they relate to environmental cleanup of well sites or other environmental restoration procedures. In connection with acquisitions of existing or previously drilled well bores, we may not be aware of what environmental safeguards were taken at the time such wells were drilled or during such time the wells were operated. Should it be determined that a liability exists with respect to any environmental cleanup or restoration, we would be responsible for curing such a violation.

We account for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed. Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated.

Fair Value Measurements

Certain financial instruments are reported at fair value on our consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost). These approaches are considered Level 3 in the fair value hierarchy.

The carrying values of financial instruments comprising cash and cash equivalents, payables, receivables, related party accounts receivable/payable and advances from joint interest owners approximate fair values due to the short-term maturities of these instruments and are classified as Level 1 in the fair value hierarchy. The carrying value of the Senior Notes is based on estimates of current rates available for similar issues with similar maturities and are classified as Level 2 in the fair value hierarchy. The carrying value reported for the Credit Facility approximates fair value because the underlying instruments are at interest rates which approximate current market rates and is considered Level 2 in the fair value hierarchy. Assets and liabilities accounted for at fair value on a non-recurring basis in accordance with the fair value hierarchy include the initial recognition of asset retirement obligations and the fair value of oil and natural gas properties when acquired in a business combination or assessed for impairment and are considered Level 3 in the fair value hierarchy.

Derivative Contracts

We report the fair value of derivatives on the consolidated balance sheets in derivative assets and derivative liabilities as either current or non-current based on the timing of the settlement of individual trades. Trades that are scheduled to settle in the next twelve months are reported as current. The Company nets derivative assets and liabilities in the consolidated balance sheet whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract.

For the years ended December 31, 2023 and 2022, we have not designated our derivative contracts as hedges for accounting purposes, and therefore changes in the fair value of derivatives are recognized in earnings. Cash settlements of contracts are included in cash flows from operating activities in the consolidated statement of cash flows. Derivative contracts are settled on a monthly basis.

The fair value of derivatives is established using index prices, volatility curves and discount factors. The value we report in our consolidated financial statements is as of a point in time and subsequently changes as these estimates are revised to reflect actual results, changes in market conditions and other factors.

The use of derivatives involves the risk that the counterparties to such contracts will be unable to meet their obligations under the terms of the agreement. To minimize the credit risk with derivative instruments, it is our policy to enter into derivative contracts primarily with counterparties that are financial institutions that are also lenders within our Credit Facility. Under the terms of the current counterparties' contracts, only those that are lenders under our Credit Facility are secured by the same collateral as outlined in our Credit Facility. The counterparties are not required to provide credit support to the Company. See further discussion in Note 6 – Derivative Instruments.

Leases

The Company's current leases include office space, office equipment, and field vehicles. The Company reviews all contracts to determine if a lease exists at contract inception. A lease exists when the Company has the right to obtain substantially all of the economic benefit of a specific asset and to control the use of that asset over the term of the agreement. Identified leases are classified as an operating or finance lease, which determines the recognition, measurement and presentation of expenses. As of December 31, 2023 and 2022, the Company did not have any finance leases. Operating leases are capitalized on the consolidated balance sheets at commencement through a lease right-of-use ("ROU") asset and lease liability representing the present value of lease payments over the lease term. In addition to the present value of lease payments, the operating lease ROU asset includes any lease payments made to the lessor prior to lease commencement less any lease incentives and initial direct costs incurred. Options to extend or terminate leases are included in the lease term when it is reasonably certain the Company will exercise the option. For operating leases, lease costs are recognized on a straight-line basis over the term of the lease.

The present value of operating lease payments and amortization of the lease liability is calculated using a discount rate. When available, the Company uses the rate implicit in the lease as the discount rate; however, some of the Company’s leases do not provide a readily determinable implicit rate. In such cases, the Company is required to use its incremental borrowing rate ("IBR"). The Company’s IBR reflects the estimated rate of interest that the Company would pay to borrow on a collateralized basis over a similar term and amount equal to the lease payments in a similar economic environment. The Company is required to reassess the discount rate for any new and modified lease contracts as of the lease effective date. The weighted-average discount rate was 9.56 % and 3.18 %, respectively, at December 31, 2023 and 2022. The weighted average remaining lease term was 2.3 years and 2.4 years, respectively, at December 31, 2023 and 2022. Lease expense was $ 0.8 million and $ 0.5 million, respectively, for the years ended December 31, 2023 and 2022.

	December 31,	
	2023	2022
	(In thousands)	
ROU asset	$ 1,890	$ 1,370
Current lease liability	$ 985	$ 539
Long-term lease liability	$ 938	$ 838

The ROU asset and current lease liability are included in other non-current assets and other current liabilities and non-current lease liabilities, respectively, on the consolidated balance sheets. Lease expense for the Company is included in general and administrative costs on the consolidated statements of operations.

Recent Accounting Pronouncements

In December 2023, the FASB issued ASU 2023-09 Income Taxes (Topic 740) Improvements to Income Tax Disclosures which requires disaggregated information about the Company's effective tax rate reconciliation and income taxes paid. This ASU is effective for the Company's fiscal year 2025. Early adoption is permitted. The Company is currently evaluating income tax disclosures related to its annual report for fiscal year 2025.

(4) Acquisitions of Oil and Natural Gas Properties

New Mexico Acquisition

On April 3, 2023, the Company completed the New Mexico Acquisition from Pecos for approximately $ 330 million, before customary purchase price adjustments. The assets acquired are located in Eddy County, New Mexico, and include approximately 10,600 total contiguous net acres of leasehold. The acquisition included 18 net horizontal wells and 250 net vertical wells. Additionally, the assets added significant drilling locations to the Company's inventory.

The Company funded the New Mexico Acquisition through a combination of borrowings under the Credit Facility and proceeds from the issuance of $ 200 million of Senior Notes, including application of a $ 33 million escrow deposit paid during the three months ended March 31, 2023 with borrowings under the Credit Facility. For further information regarding the financing for the New Mexico Acquisition, see Note 9 - Long-Term Debt.

The New Mexico Acquisition qualified as a business combination using the acquisition method of accounting. The assets acquired and liabilities assumed were recognized at fair value as of the acquisition date. The fair value measurements of the oil and natural gas properties acquired and asset retirement obligations assumed were derived utilizing an income approach and based, in part, on significant inputs not observable in the market. These inputs represent Level 3 measurements in the fair value hierarchy and include, but are not limited to, estimates of future production volumes, future development, future operating costs, future cash flows and the use of weighted average cost of capital. These inputs required the use of significant judgments and estimates at the date of valuation, and use of different estimates and judgments could yield different results.

The following presents the allocation of the total purchase price of the New Mexico Acquisition to the identified assets acquired and liabilities assumed based on estimated fair value as of the Closing Date:

Purchase price allocation as of December 31, 2023 (in thousands):		
Total cash consideration	$	324,686
Assets acquired:		
Inventory	$	2,980
Oil and natural gas properties		342,308
Other		149
Amount attributable to assets acquired	$	345,437
Fair value of liabilities assumed:		
Revenue payable	$	1,475
Asset retirement obligations		19,276
Amount attributable to liabilities assumed	$	20,751
Net assets acquired	$	324,686

The transaction costs of $ 5.8 million for the year ended December 31, 2023 relate to the New Mexico Acquisition. During the year ended December 31, 2022, the transaction costs of $ 2.6 million relate to a potential business combination and related financing that the Company pursued but ultimately chose not to consummate. These costs are included in the consolidated statements of operations.

Post-Acquisition Operating Results

The results of operations attributable to the New Mexico Acquisition since the Closing Date have been included in the consolidated statements of operations and include $ 79.3 million of total revenue, net and $ 51.8 million of earnings for the year ended December 31, 2023.

Pro Forma Operating Results (Unaudited)

The following unaudited pro forma combined results for the years ended December 31, 2023 and 2022 reflect the consolidated results of operations of the Company as if the New Mexico Acquisition had occurred on January 1, 2022. The unaudited pro forma information includes adjustments for (i) transaction costs being reclassified to 2022 instead of being recorded during the year ended December 31, 2023 (ii) amortization for the discount and deferred financing costs related to the Senior Notes and Credit Facility, (iii) depletion, depreciation and amortization expense, and (iv) interest expense related to the financing for the New Mexico Acquisition. These adjustments remove such costs, as described above, that would not have been recognized had the Company not acquired the assets. In addition, the pro forma information has been effected for taxes with a 23 % tax rate.

	Year Ended December 31,			
	2023		2022	
	(In thousands, except per share amounts)			
Total revenues	$	405,642	$	435,157
Net income	$	121,466	$	129,741
Basic net income per common share	$	6.16	$	6.64
Diluted net income per common share	$	6.07	$	6.59

The unaudited pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Company would have reported had the New Mexico Acquisition been completed as of January 1, 2022 and should not be taken as indicative of the Company's future combined results of operations. The actual results may differ significantly from that reflected in the unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

(5) Oil and Natural Gas Properties

Oil and natural gas properties are summarized below:

	December 31,	
	2023	2022
	(In thousands)	
Proved	$ 895,783	$ 516,011
Unproved	100,216	12,770
Work-in-progress	57,004	45,169
	1,053,003	573,950
Accumulated depletion, amortization and impairment	(206,102)	(133,848)
Total oil and natural gas properties, net	$ 846,901	$ 440,102

As of December 31, 2023, the Company had no exploratory wells included in work-in-progress. In 2022, the Company had one exploratory well drilled but uncompleted that was included in work-in-progress with associated well costs of $ 3.8 million. During the year ended December 31, 2023, the Company determined this exploratory well was not capable of producing commercial quantities and, as such, expensed the associated drilling costs.

Depletion and amortization expense for proved oil and natural gas properties was $ 62.5 million and $ 31.5 million for the years ended December 31, 2023 and 2022, respectively.

Exploration costs were $ 4.2 million and $ 2.0 million for the years ended December 31, 2023 and 2022, respectively, and were primarily attributable to exploratory well expense and the expiration of oil and natural gas leases in 2023 and the expiration of oil and natural gas leases in 2022.

Impairment of Proved Properties

Certain proved oil and natural gas properties were impaired during the year ended December 31, 2023. Our impairment test involved a step assessment to determine if the net book value of our proved oil and natural gas properties is expected to be recovered from the estimated undiscounted future net cash flows. We calculated the expected undiscounted future net cash flows of our long-lived assets using management’s assumptions and expectations.

Certain oil and natural gas properties in Texas outside of the Company's acreage in the Champions Field failed the initial step assessment, which looks at the carrying value compared to undiscounted cash flows for these properties. For these assets, we used a discounted cash flow analysis to estimate fair value. The expected future net cash flows were discounted using a rate of 10.0 %, which we believe represents the estimated weighted average cost of capital of a market participant. Based on this assessment of our long-lived assets impairment test, we recognized a $ 9.8 million impairment because the carrying value exceeded the estimated fair market value as of the year ended December 31, 2023. The Company recognized an impairment of $ 7.3 million on proved properties in New Mexico, outside of the Redlake field, for the year ended December 31, 2022. See further discussion of our fair value assumptions in Note 7 - Fair Value Measurements.

(6) Derivative Instruments

Oil and Natural Gas Contracts

The Company uses commodity based derivative contracts to reduce exposure to fluctuations in oil and natural gas prices. While the use of these contracts limits the downside risk for adverse price changes, their use also limits future revenues from favorable price changes. We have not designated our derivative contracts as hedges for accounting purposes, and therefore changes in the fair value of derivatives are included and recognized in other income (expense) in the consolidated statements of operations.

As of December 31, 2023, the Company's oil and natural gas derivative instruments consisted of the following types:

- Fixed Price Swaps – the Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.
- Costless collars – the combination of a put option (fixed floor) and call option (fixed ceiling), with the options structured so that the premium paid to purchase the put option is offset by the premium received from the sale of the call option. If the market price exceeds the call strike price or falls below the put strike price, we receive the fixed price and pay the market price. If the market price is between the put and the call strike price, no payments are due from either party.
- Basis Protection Swaps – basis swaps are settled based on differences between a fixed price differential and the differential between the settlement prices of two referenced indexes. We receive the fixed price differential and pay the differential between the referenced indexes.

The following table summarizes the open financial derivative positions as of December 31, 2023, related to oil and natural gas production:

		Weighted Average Price		
Calendar Quarter / Year	Notional Volume	Fixed	Put	Call
			($ per unit)	
Oil Swaps (Bbl)				
Q1 2024	195,000	$ 73.35		
Q2 2024	225,000	$ 72.12		
Q3 2024	225,000	$ 72.12		
Q4 2024	225,000	$ 72.12		
2025	330,000	$ 71.86		
Natural Gas Swaps (Mcf)				
Q1 2024	750,000	$ 3.48		
Q2 2024	600,000	$ 3.21		
Q3 2024	600,000	$ 3.21		
Q4 2024	450,000	$ 3.67		
2025	600,000	$ 3.85		
Oil Collars (Bbl)				
Q1 2024	520,000		$ 61.41	$ 84.00
Q2 2024	390,000		$ 61.08	$ 85.76
Q3 2024	366,000		$ 61.00	$ 83.61
Q4 2024	345,000		$ 60.87	$ 84.26
2025	728,000		$ 62.51	$ 76.90
Natural Gas Collars (Mcf)				
Q1 2024	300,000		$ 3.40	$ 4.50
Q2 2024	405,000		$ 3.01	$ 3.68
Q3 2024	405,000		$ 3.01	$ 3.68
Q4 2024	405,000		$ 3.50	$ 4.45
2025	1,215,000		$ 3.28	$ 4.30
Oil Basis Swaps (Bbl)				
Q1 2024	330,000	$ 0.97		
Q2 2024	330,000	$ 0.97		
Q3 2024	330,000	$ 0.97		
Q4 2024	330,000	$ 0.97		

Interest Rate Contracts

The Company entered into floating-to-fixed interest rate swaps, in which it will receive a floating market rate equal to one-month Chicago Mercantile Exchange Term Secured Overnight Financing Rate ("SOFR") Rate and will pay a fixed interest rate to manage future interest rate exposure related to the Company's Credit Facility.

The following table summarizes the open interest rate derivative positions as of December 31, 2023:

Open Coverage Period	Notional Amount	Fixed Rate
	(In thousands)	
April 2024 - April 2026	$ 30,000	3.18 %
April 2024 - April 2026	$ 50,000	3.04 %

Balance Sheet Presentation of Derivatives

The following tables present the location and fair value of the Company’s derivative contracts included in the consolidated balance sheets as of December 31, 2023 and 2022:

	December 31, 2023		
Balance Sheet Classification	Gross Fair Value	Amounts Netted	Net Fair Value
		(In thousands)	
Current derivative assets	$ 8,948	$ (3,935)	$ 5,013
Non-current derivative assets	6,687	(4,391)	2,296
Current derivative liabilities	(4,295)	3,935	(360)
Non-current derivative liabilities	(4,391)	4,391	—
Total	$ 6,949	$ —	$ 6,949

	December 31, 2022		
Balance Sheet Classification	Gross Fair Value	Amounts Netted	Net Fair Value
		(In thousands)	
Current derivative assets	$ 64	$ (44)	$ 20
Non-current derivative assets	9	(9)	—
Current derivative liabilities	(16,516)	44	(16,472)
Non-current derivative liabilities	(21)	9	(12)
Total	$ (16,464)	$ —	$ (16,464)

The following table presents the components of the Company's gain (loss) on derivatives, net for the periods presented below:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Settlements on derivative contracts	$ (17,221)	$ (75,257)
Non-cash gain on derivatives	23,414	23,683
Gain (loss) on derivatives, net	$ 6,193	$ (51,574)

(7) Fair Value Measurements

The FASB has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

The carrying values of financial instruments comprising cash and cash equivalents, payables, receivables, and advances from joint interest owners approximate fair values due to the short-term maturities of these instruments and are classified as Level 1 in the fair value hierarchy. The carrying value reported for the revolving line of credit approximates fair value because the underlying instruments are at interest rates which approximate current market rates. The fair value of the Senior Notes is based on estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy. The oil and natural gas properties acquired and asset retirement obligations assumed in the New Mexico Acquisition are considered Level 3 measurements.

Assets and Liabilities Measured on a Recurring Basis

The fair value of commodity derivatives and interest rate swaps is estimated using discounted cash flow calculations based upon forward curves and are classified as Level 2 in the fair value hierarchy. The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2023 and 2022, by level within the fair value hierarchy:

	December 31, 2023			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets:				
Commodity derivative assets	$ —	$ 14,766	$ —	$ 14,766
Interest rate assets	$ —	$ 869	$ —	$ 869
Financial liabilities:				
Commodity derivative liabilities	$ —	$ (8,686)	$ —	$ (8,686)

	December 31, 2022			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Financial assets:				
Commodity derivative assets	$ —	$ 73	$ —	$ 73
Financial liabilities:				
Commodity derivative liabilities	$ —	$ (16,537)	$ —	$ (16,537)

The following table summarizes the fair value and carrying amount of the Company's financial instruments.

	December 31, 2023		December 31, 2022	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Credit Facility (Level 2)	$ 185,000	$ 185,000	$ 56,000	$ 56,000
Senior Notes (Level 2) (1)	$ 170,959	$ 185,346	$ —	$ —

(1) The carrying value reported for the Senior Notes is shown net of unamortized discount and unamortized deferred financing costs.

The carrying value reported for the Credit Facility approximates fair value because the underlying instruments are at interest rates which approximate current market rates. The fair value of the Senior Notes was determined utilizing a discounted cash flow approach.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Assets and liabilities accounted for at fair value on a non-recurring basis in accordance with the fair value hierarchy include the initial recognition of asset retirement obligations and the fair value of oil and natural gas properties when acquired in a business combination or assessed for impairment.

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs used to determine the fair value include estimates of: (i) reserves; (ii) future commodity prices; (iii) operating and development costs; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the Company's estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that the

Company's management believes will impact realizable prices. These inputs require significant judgments and estimates by the Company's management at the time of the valuation.

The fair value of asset retirement obligations incurred and acquired during the years ended December 31, 2023 and 2022, totaled approximately $ 19.4 million and $ 0.4 million, respectively. The fair value of additions to the asset retirement obligation liabilities is measured using valuation techniques consistent with the income approach, which converts future cash flows to a single discounted amount. Significant inputs to the valuation include: (i) estimated plug and abandonment cost per well for all oil and natural gas wells and for all disposal wells; (ii) estimated remaining life per well; (iii) future inflation factors; and (iv) our average credit-adjusted risk-free rate. These assumptions represent Level 3 inputs.

If the carrying amount of our oil and natural gas properties exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The fair value of our oil and natural gas properties is determined using valuation techniques consistent with the income and market approach. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with the expected cash flow projected.

For the year ended December 31, 2023, the Company recognized an impairment charge to its oil and natural gas properties of $ 9.8 million related to acreage in Texas outside of its Champions Field. In preparing this assessment, the Company utilized a discounted cash flow approach to estimate fair value. The assumptions utilized in the discounted cash flow are considered Level 3, consistent with the discussion above. Under the discounted cash flow methodology, the expected future net cash flows were discounted using a weighted average cost of capital rate reflective of a market participant rate. Additionally, the assumptions utilized include the future commodity prices for oil and natural gas based on NYMEX strip pricing for West Texas Intermediate ("WTI") and Henry Hub ("HH"), as adjusted for differentials (using the Company's historical average of differentials, which approximate a market participant's differentials) and operating cost assumptions based on the Company's historical LOE, which are deemed to estimate a market participant's operating costs. See further discussion of our impairment in Note 5 - Oil and Natural Gas Properties.

(8) Transactions with Related Parties

Contract Services

RPOC provides certain administrative services to Combo Resources, LLC ("Combo") and is also the contract operator on behalf of Combo in exchange for a monthly fee of $ 100 thousand and reimbursement of all third party expenses pursuant to a contract services agreement. Additionally, RPOC provides certain administrative and operational services to Riley Exploration Group, LLC ("REG") in exchange for a monthly fee of $ 100 thousand pursuant to a contract services agreement. Combo and REG are portfolio companies of Yorktown Energy Partners XI, L.P. ("Yorktown XI"), certain managed funds of which have investments in the Company (all deemed to be related parties). As of December 31, 2023, our Executive Vice President - Business Intelligence was the President of both REG and Combo, as well as a board member of Combo.

The following table presents revenues from and related cost for contract services for related parties:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Combo	$ 1,200	$ 1,200
REG	1,200	1,200
Contract services - related parties	$ 2,400	$ 2,400
Cost of contract services	$ 579	$ 450

The Company had amounts payable to Combo of $ 0.7 million and $ 0.4 million at December 31, 2023 and 2022, respectively, which are reflected in other current liabilities in the accompanying consolidated balance sheets. Amounts due to Combo reflect the revenue, net of any expenditures for wells and fees due under the contract services agreement, for Combo's net working interest in wells that the Company operates on Combo's behalf. See Note 14 - Subsequent Events for additional information regarding arrangements with Combo occurring after December 31, 2023.

Consulting and Legal Fees

The Company has an engagement agreement with di Santo Law PLLC ("di Santo Law"), a law firm owned by Beth di Santo, a member of our Board of Directors, pursuant to which di Santo Law's attorneys provide legal services to the Company. For the years ended December 31, 2023 and 2022, the Company incurred legal fees from di Santo Law of approximately $ 1.2 million, and $ 0.7 million, respectively. As of December 31, 2023, the Company had approximately $ 0.6 million in amounts accrued for di Santo Law, which was included in accrued liabilities in the accompanying consolidated balance sheets.

(9) Long-Term Debt

The following table summarizes the Company's outstanding debt:

	December 31,	
	2023	2022
	(In thousands)	
Credit Facility	$ 185,000	$ 56,000
Senior Notes		
Principal	$ 185,000	$ —
Less: Unamortized discount[(1)]	10,117	—
Less: Unamortized deferred financing costs[(2)]	3,924	—
Total Senior Notes	$ 170,959	$ —
Total debt	$ 355,959	$ 56,000
Less: Current portion of long-term debt[(3)]	20,000	—
Total long-term debt	$ 335,959	$ 56,000

(1) Unamortized discount on long-term debt is amortized over the life of the respective debt.

(2) As of December 31, 2023, unamortized deferred financing costs are attributable to and amortized over the life of the Senior Notes.

(3) As of December 31, 2023, the current portion of long-term debt reflects $ 20 million due on the Senior Notes over the next twelve months.

Debt maturities as of December 31, 2023, excluding unamortized deferred financing costs, are as follows:

	Year Ending December 31,
	(In thousands)
2024	$ 20,000
2025	20,000
2026	205,000
2027	20,000
2028	105,000
Thereafter	—
Total	$ 370,000

Credit Facility

On September 28, 2017, REP LLC entered into a credit agreement (the "Credit Agreement") to establish a senior secured Credit Facility with a syndicate of banks including SunTrust Bank, now Truist Bank as successor by merger, as administrative agent. The Credit Facility had an initial borrowing base of $ 25 million with a maximum facility amount of $ 500 million. On February 22, 2023, the Company amended its Credit Facility to, among other things, allow for the issuance of unsecured senior notes of up to $ 200 million. On April 3, 2023, and concurrent with the closing of the New Mexico Acquisition, the Company entered into the fourteenth amendment (the "Fourteenth Amendment") to the Credit Facility to, among other things, increase the maximum facility amount to $ 1.0 billion and the borrowing base from $ 225 million to $ 325 million, resulting in the addition of new lenders to the lending group. On November 14, 2023, through the semi-annual redetermination process, the Credit Facility was amended to increase the borrowing base from $ 325 million to $ 375 million. The Credit Agreement is set to mature in April 2026. Substantially all of the Company's assets are pledged to secure the Credit Facility.

The borrowing base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. During these redetermination periods, the Company's borrowing base may be increased or may be reduced in certain circumstances. The Credit Facility allows for SOFR Loans and Base Rate Loans (each as defined in the Credit Agreement). The interest rate on each SOFR Loan will be the adjusted Term SOFR for the applicable interest period plus a margin between 2.75 % and 3.75 % (depending on the borrowing base utilization percentage). The annual interest rate on each Base Rate Loan will be the Base Rate for the applicable interest period plus a margin between 1.75 % and 2.75 % (depending on the borrowing base utilization percentage). The Company is also subject to an unused commitment fee of between 0.375 % and 0.500 % (depending on the borrowing base utilization percentage).

The Credit Agreement contains certain covenants, which, among other things, require the maintenance of (i) a total leverage ratio of not more than 3.0 to 1.0 and (ii) a minimum current ratio of not less than 1.0 to 1.0 as of the last day of any quarter. The Credit Agreement also contains a total leverage ratio for Restricted Payments, as defined in the Credit Agreement, after giving pro forma effect to such Restricted Payments, which includes payments to any holder of the Company's shares, would not exceed 2.50 to 1.0. If the Company's leverage ratio, after giving pro forma effect to such Restricted Payments (as defined in the Credit Agreement), is above 2.0 to 1.0, then an additional test of free cash flow is applied, and the Company will only be permitted to make such Restricted Payments if such payment does not exceed the Company's free cash flow. The Company is also required to limit its cash balance to less than $ 15 million or 10 % of the borrowing base, whichever is greater. If the Company's cash balance exceeds this limit on the last business day of the month, the Company will be required to apply the excess to reduce its Credit Facility borrowings. The Credit Agreement also contains other customary affirmative and negative covenants and events of default. The Company must maintain a minimum hedging requirement included in the Credit Agreement for oil and natural gas based on its proved developed producing projected volumes on a rolling 24-month basis. The following table summarizes the Credit Facility balances:

	December 31,	
	2023	2022
	(In thousands)	
Outstanding borrowings	$ 185,000	$ 56,000
Available under the borrowing base	$ 190,000	$ 169,000

Senior Notes

On April 3, 2023, and concurrent with the closing of the New Mexico Acquisition, the Company (as "Issuer") completed its issuance of $ 200 million aggregate principal amount of 10.50 % senior unsecured notes with final maturity April 2028 pursuant to a note purchase agreement (the "Note Purchase Agreement"), with the Senior Notes issued at a 6 % discount. The net proceeds from the Senior Notes were used to fund a portion of the purchase price and related fees, costs and expenses for the New Mexico Acquisition.

Interest is due and payable at the end of each quarter. In addition to interest, the Issuer will repay 2.50 % of the original principal amount each quarter resulting in $ 5 million quarterly principal payments until the maturity of the Senior Notes. As of December 31, 2023, the Company had $ 20 million in current liabilities on the consolidated balance sheet related to the quarterly principal payments due within the next 12 months.

The Issuer may, at its option, redeem, at any time and from time to time on or prior to April 3, 2026, some or all of the Senior Notes at 100 % of the principal amount thereof plus the make-whole amount plus a premium of 5.25 % as set forth in the Note Purchase Agreement plus accrued and unpaid interest, if any. After April 3, 2026, but on or prior to October 3, 2026, the Issuer may, at its option, redeem, at any time and from time to time some or all of the Senior Notes at 100 % of the principal amount thereof plus a premium of 5.25 % as set forth in the Note Purchase Agreement plus accrued and unpaid interest, if any. After October 3, 2026, the Issuer may redeem some or all of the Senior Notes at 100 % of the principal amount thereof plus accrued and unpaid interest, if any. The principal remaining outstanding at the time of maturity is required to be paid in full by the Issuer. Certain note features, including those discussed above, were evaluated and deemed to be remote. Due to the remote nature, the fair value of these features was estimated to be approximately zero.

The Senior Notes contain certain covenants, which, among other things, require the maintenance of (i) a total leverage ratio of less than 3.0 to 1.0 and (ii) an asset coverage ratio greater than 1.50 to 1.0. The Senior Notes also contain a total leverage ratio and an asset coverage ratio for Restricted Payments, as defined in the Senior Notes. The leverage ratio, after giving pro forma effect to such Restricted Payments, cannot exceed 2.0 to 1.0, and the asset coverage ratio, after giving effect to such Restricted Payments, must be greater than or equal to 1.50 to 1.0. In addition to and after giving effect to such Restricted Payments, the outstanding balance on the Company's Credit Facility must be greater than or equal to 15 % of the lesser of the then effective Borrowing Base and the Aggregate Elected Commitment Amount. Upon issuance of the Senior Notes, the Company must maintain a minimum hedging requirement included within the Senior Notes for oil and natural gas based on its proved developed producing projected volumes for each commodity on a rolling 18-month basis.

The Senior Notes are general unsecured obligations ranking equally in right of payment with all other senior unsecured indebtedness of the Company and are senior in right of payment to all existing and future subordinated indebtedness of the Company. The Note Purchase Agreement contains customary terms and covenants, including limitations on the Company's ability to incur additional secured and unsecured indebtedness.

The following table summarizes the Company's interest expense:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Interest expense	$ 30,231	$ 864
Capitalized interest	(3,187)	(1022)
Amortization of deferred financing costs	2,278	731
Amortization of discount on Senior Notes	1,883	—
Unused commitment fees on Credit Facility	611	517
Total interest expense, net	$ 31,816	$ 1,090

As of December 31, 2023 and 2022, the weighted average interest rate on outstanding borrowings under the Credit Facility was 8.68 % and 7.17 %, respectively.

As of December 31, 2023, the Senior Notes had $ 10.1 million of unamortized discount and $ 3.9 million of unamortized deferred financing costs, resulting in an effective interest rate of 13.38 % during the year ended December 31, 2023.

As of December 31, 2023 and 2022, the Company was in compliance with all covenants contained in the Credit Agreement and the Note Purchase Agreement.

(10) Shareholders' Equity

Dividends

Cash dividends for the periods presented were declared for all issued and outstanding common shares, including vested and unvested under the respective Long-Term Incentive Plan in effect during the period of dividend declaration. The portion of the cash attributable to the unvested restricted shares issued under the Amended and Restated 2021 Long-Term Incentive Plan (the "A&R LTIP") is included in accrued liabilities on the consolidated balance sheets and will be paid in cash once the unvested restricted shares fully vest. See Note 9 - Long-Term Debt for discussion over the Company's restrictions on certain payments, including dividends.

The table below summarizes the following cash distributions declared to common shareholders during the periods presented below:

Quarter Ended	Per Share Distribution	Total Distribution
		(In thousands)
2023		
December 31, 2023	$ 0.36	$ 7,477
September 30, 2023	$ 0.34	$ 6,737
June 30, 2023	$ 0.34	$ 6,846
March 31, 2023	$ 0.34	$ 6,851
2022		
December 31, 2022	$ 0.34	$ 6,837
September 30, 2022	$ 0.31	$ 6,159
June 30, 2022	$ 0.31	$ 6,159
March 31, 2022	$ 0.31	$ 6,154

Share-Based Compensation

On April 21, 2023, at the Company's annual meeting of stockholders, the Company's stockholders approved the A&R LTIP that increased the total number of shares of Common Stock, par value $ 0.001 per share, by 950,000 shares that may be utilized for awards pursuant to the Plan from 1,387,022 to 2,337,022 . The A&R LTIP had 1,075,626 shares available as of December 31, 2023.

2021 Long-Term Incentive Plan

The A&R LTIP will provide for potential grants of: (i) incentive stock options qualified as such under U.S. federal income tax laws ("ISO's"); (ii) stock options that do not qualify as incentive stock options; (iii) stock appreciation rights, or SARs; (iv) restricted stock awards; (v) restricted stock units, or RSUs, (vi) stock awards; (vii) performance awards; (viii) dividend equivalents; (ix) other stock-based awards; (x) cash awards; and (xi) substitute awards, all of which will collectively be referred to as the "Awards".

The A&R LTIP authorizes the Compensation Committee to administer the plan and designate eligible persons as participants, determine the type or types of Awards to be granted to an eligible person, determine the number of shares of stock or amount of cash to be covered by the Awards, approve the forms of award agreements for use under the plan, determine the terms and conditions of any Award, modify, waive or adjust any term or condition of an Award that has been granted, among other responsibilities delegated by the Company's Board.

Restricted Shares: The Company granted 346,869 and 367,420 restricted shares to executives, employees and independent directors of the Company during the years ended December 31, 2023 and 2022, respectively. The holders of these restricted shares receive dividends, in arrears, once the shares vest. The Company has accrued for these dividends which are reported in accrued liabilities and other non-current liabilities. All restricted shares granted have a service period between 3 and 36 months. The Company estimates the fair values of the restricted shares as the closing price of the Company's common stock on the grant date of the award, with the expense amortized on a straight-line basis and recognized over the vesting period.

The following table presents the Company's restricted stock activity during the year ended December 31, 2023 under the A&R LTIP:

2021 Long-Term Incentive Plan

	Restricted Shares	Weighted Average Grant Date Fair Value
Unvested at December 31, 2022	536,209	$ 18.39
Granted[1]	346,869	$ 28.68
Vested[2]	(329,005)	$ 19.38
Forfeited	(32,076)	$ 24.83
Unvested at December 31, 2023	521,997	$ 24.37

(1) For the year ended December 31, 2022, the weighted average fair value of restricted shares granted during the year was $ 17.63 .

(2) For the years ended December 31, 2023 and 2022, the total fair value of restricted shares vested during the year was $ 6.4 million and $ 3.7 million, respectively.

For the years ended December 31, 2023 and 2022, the total share-based compensation expense is $ 7.0 million and $ 3.9 million, respectively. For the year ended December 31, 2023, share based compensation expense also includes expense associated with equity awards attributable to a separation agreement with a former Company executive. Share-based compensation expense is included in general and administrative costs on the Company's consolidated statement of operations for the restricted share awards granted under the A&R LTIP. At the time of the forfeiture, the Company will recognize any forfeited shares as a reduction to share-based compensation expense on the consolidated statement of operations and a decrease to shareholders' equity on the consolidated balance sheet. Any unpaid dividends on forfeited shares will be recognized as a decrease to accrued liabilities and an increase to shareholders' equity on the consolidated balance sheet. Approximately $ 11.1 million of additional share-based compensation expense will be recognized over the weighted average life of 27 months for the unvested restricted share awards as of December 31, 2023 granted under the A&R LTIP.

ATM Program

On September 1, 2023, the Company entered into an Equity Distribution Agreement in connection with an at-the-market equity sales program ("ATM") pursuant to which the Company may offer and sell from time to time up to an aggregate $ 50 million in shares of the Company's common stock through its agents. The offer and sale of the shares has been registered under the Securities Act of 1933, as amended ("Securities Act"), pursuant to the Company’s registration statement on Form S-3, as amended. A prospectus supplement related to the offering of the shares, as defined in Rule 415(a)(4) promulgated under the Securities Act was filed September 1, 2023. The Company intends to use the net proceeds from any offering for working capital purposes and other general corporate purposes, including, but not limited to, financing of capital expenditures, repayment or refinancing of outstanding debt, financing acquisitions or investments, financing other business opportunities, and general working capital purposes.

During the year ended December 31, 2023, the Company executed sales under the ATM program of 8,939 shares which generated proceeds of approximately $ 280 thousand, net of approximately $ 278 thousand of fees including expenses associated with establishing the ATM program and filing of the related prospectus supplement. As of December 31, 2023, the Company had remaining capacity to sell up to an additional $ 49.7 million of common stock under the ATM program.

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(11) Income Taxes

The components of the Company's consolidated provision for income taxes from continuing operations are as follows:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Current income tax expense:		
Federal	$ 5,852	$ 4,026
State	1,020	446
Total current income tax expense	$ 6,872	$ 4,472
Deferred income tax expense:		
Federal	$ 24,305	$ 27,393
State	3,284	979
Total deferred income tax expense	$ 27,589	$ 28,372
Total income tax expense	$ 34,461	$ 32,844

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax bases of assets and liabilities. The Company's net deferred tax position is as follows:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Deferred tax assets		
Non-cash gain on derivatives	$ —	$ 3,563
Intangibles	163	182
Share-based compensation	772	421
Interest expense limitation	3,861	—
Accruals and other	1,123	484
Net operating loss	2,700	2,812
Total deferred tax assets	8,619	7,462
Oil and natural gas assets	(79,761)	(52,665)
Other fixed assets	(661)	(553)
Unrealized gain on derivatives	(1,542)	—
Total deferred tax liabilities	(81,964)	(53,218)
Net deferred tax liabilities	$ (73,345)	$ (45,756)

A reconciliation of the statutory federal income tax rate to the Company's effective income tax rate is as follows:

	Year Ended December 31,	
	2023	2022
Tax at statutory rate	21.0 %	21.0 %
Nondeductible compensation	0.7 %	0.2 %
Share-based compensation	(0.5)%	— %
State income taxes, net of federal benefit	2.4 %	0.7 %
Other	— %	(0.2)%
Effective income tax rate	23.6 %	21.7 %

The Company's federal income tax returns for the years subsequent to December 31, 2019 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for various periods subsequent to December 31, 2018. The Company currently believes that all other significant filing positions are highly certain and that all of its other significant income tax positions and deductions would be sustained under audit or the final resolution would not have a material effect on the consolidated financial statements. Therefore, the Company has not established any significant reserves for uncertain tax positions.

Section 382 of the Internal Revenue Code limits the utilization of U.S. net operating loss ("NOL") carryforwards following a change in control. The Merger caused a stock ownership change for purposes of Section 382 which is subject to an approximate annual limit. The Company has federal NOLs subject to the annual Section 382 limit of $ 12.9 million of which $ 4.1 million will expire beginning in 2024 with the remaining $ 8.8 million of the NOLs not expiring. Additionally, the Company has no federal NOLs generated after the Merger that are not limited by Section 382 and are not subject to expiration. We believe it is more likely than not the tax benefit of these net operating losses will be fully realized, as such no valuation allowance has been recorded. The deferred tax assets for the net operating losses, along with the other deferred tax assets as shown in the table above, are presented net with deferred tax liabilities, which primarily consist of book and tax depreciation differences.

(12) Net Income Per Share

The Company calculated net income per share using the treasury stock method. The table below sets forth the computation of basic and diluted net income per share for the periods presented below:

	Year Ended December 31,	
	2023	2022
	(In thousands, except per share amounts)	
Net income	$ 111,591	$ 118,011
Basic weighted-average common shares outstanding	19,705	19,553
Restricted shares	295	133
Diluted weighted-average common shares outstanding	20,000	19,686
Basic net income per common share	$ 5.66	$ 6.04
Diluted net income per common share	$ 5.58	$ 5.99

The following shares were excluded from the calculation of diluted net income per share due to their anti-dilutive effect for the periods presented:

	Year Ended December 31,	
	2023	2022
Restricted shares	294,817	405,114

(13) Commitments and Contingencies

Legal Matters

Due to the nature of the Company's business, the Company may at times be subject to claims and legal actions. The Company accrues liabilities when it is probable that future costs will be incurred, and such costs can be reasonably estimated. Such accruals are based on developments to date and the Company’s estimates of the outcomes of these matters. The Company did not recognize any material liability for legal matters as of December 31, 2023 and December 31, 2022. Management believes it is remote that the impact of such matters will have a materially adverse effect on the Company’s financial position, results of operations, or cash flows.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. The Company had no material environmental liabilities as of December 31, 2023 or December 31, 2022.

Contractual Commitments

In October 2021, the Company executed an agreement related to its EOR project. This agreement is a CO2 purchase agreement that has a daily contract quantity with Kinder Morgan CO2 Company, LLC that has a primary term extending through the earlier of the total contract quantity delivered or December 31, 2025.

In August 2022, the Company entered into a second amendment on its gas gathering and processing agreement with its primary midstream counterparty, Stakeholder Midstream LLC (“Stakeholder”). Stakeholder committed to expand their gathering and processing system with a commitment from the Company to deliver an annual minimum volume to Stakeholder’s gathering system for a minimum of seven years beginning on the in-service date of the expanded plant.

In January 2023, the Company entered into an agreement to form a joint venture with Conduit Power LLC. The Company is committed to contributing its portion of capital expenditures into the joint venture company, RPC Power. In conjunction with the formation of the joint venture, the Company entered into additional agreements with RPC Power or one of its subsidiaries. These agreements include RPC Power providing operational expertise on the implementation and management of the power generation for a monthly fee of $ 20 thousand. In addition, the Company entered into a tolling agreement and committed to provide the natural gas needed to fuel onsite power generators for 10 years following the in-service date, with an automatic yearly extension until terminated by either party, for a fee based on a per MMBtu basis adjusted for contractual usage factors.

In October 2023, the Company entered into a purchase agreement for pipe related to its 2024 drilling program. Under the agreement, the Company has commitments to purchase approximately $ 13.1 million of pipe by December 2024.

(14) Subsequent Events

Dividend Declaration

On January 11, 2024, the Board of Directors of the Company declared a cash dividend of $ 0.36 per share of common stock payable on February 8, 2024 to its shareholders of record at the close of business on January 25, 2024.

Termination of Agreements between Riley and Combo

As discussed in Note 8 - Transactions with Related Parties, the Company has an MSA with Combo to provide certain services, including management of its assets, and overall company accounting, tax filings, and back-office functions. Each of Combo and Riley desired to terminate such MSA and transitioned the services under the MSA to Combo and its service providers effective as of January 31, 2024.

In addition, certain oil and natural gas properties were developed by Riley and Combo who currently jointly own interests in 6 established units in Lee and Fayette Counties, Texas. Going forward, Riley will no longer have the right to acquire interest in Combo’s leases or earn an interest in the future units formed within defined areas. Riley may participate in any wells or units to the extent Riley owns an interest in oil, gas or minerals attributable to such new well or unit. Further, Riley can continue to participate in wells drilled within each of the established units.

Power Joint Venture

On March 4, 2024, the Company made a capital contribution of $ 5.6 million to its joint venture RPC Power, which increased the total contribution to $ 11.5 million and the total ownership from 30 % to 35 %.

(15) Supplemental Oil and Gas Information (Unaudited)

Capitalized Costs

Capitalized costs include the cost of properties, equipment and facilities for oil and natural gas producing activities. Capitalized costs for proved properties include costs for oil and natural gas leaseholds where proved reserves have been identified, development wells and related equipment and facilities.

Capitalized costs for unproved properties include costs for acquiring or extending oil and natural gas leaseholds where no proved reserves have been identified. Work in progress include costs of exploratory and development wells that are in the process of drilling or in active completion, and costs of exploratory and development wells suspended or waiting on completion. For a summary of these costs, please refer to Note 5 – Oil and Natural Gas Properties.

Costs Incurred for Property Acquisition, Exploration and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and natural gas property acquisition, exploration and development activities. Costs incurred also include ARO established in the current year as well as increases or decreases to ARO resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells and construction of related production facilities.

The following summarizes the costs incurred for oil and natural gas property acquisition, exploration and development activities for the periods presented below:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Acquisition of properties		
Proved	$ 228,147	$ 450
Unproved	102,742	1,468
Exploration costs	—	157
Development costs	152,309	119,673
Total costs incurred	$ 483,198	$ 121,748

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Results of Operations

The following table includes revenues and expenses associated with the Company's oil and natural gas producing activities. They do not include any allocation of the Company's interest costs or general corporate overhead. Therefore, the following schedule is not necessarily indicative of the contribution of net earnings of the Company's oil and natural gas operations.

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Oil, natural gas and NGL sales	$ 372,647	$ 319,343
Lease operating expenses	58,817	32,458
Production and ad valorem taxes	25,559	19,273
Exploration costs	4,165	2,032
Depletion, accretion and amortization	64,471	31,500
Impairment of oil and natural gas properties	9,760	7,325
Results of operations	209,875	226,755
Income tax expense [1]	(44,493)	(48,957)
Results of operations, net of income tax expense	$ 165,382	$ 177,798

(1) The statutory combined federal and state tax rate of 21.20 % and 21.59 % is used for the years ended December 31, 2023 and.2022, respectively.

Oil, Natural Gas and NGL Quantities

Our reserve report for the year ended December 31, 2023 was prepared by Ryder Scott Company, L.P. For the year ended December 31, 2022, our reserve report was prepared by Netherland, Sewell & Associates, Inc. All reserves are located within the continental United States. Proved oil, natural gas and NGL reserves are the estimated quantities of oil, natural gas and NGLs that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimate is made. Proved developed oil, natural gas and NGL reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made. A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are decline curve analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

SUPPLEMENTAL OIL AND GAS INFORMATION - (continued)
(Unaudited)

The following table sets forth information for the periods below with respect to changes in the Company's proved (i.e., proved developed and undeveloped) reserves:

	Oil	Natural Gas	NGLs	Total
	(MBbl)	(MMcf)	(MBbl)	(MBoe)
December 31, 2021	47,021	77,486	13,471	73,407
Extensions and discoveries	9,949	13,178	2,651	14,796
Revisions	(4,871)	(1,417)	(1,224)	(6,331)
Production	(3,217)	(3,229)	(444)	(4,199)
December 31, 2022	48,882	86,018	14,454	77,673
Acquisitions	12,810	39,261	6,711	26,064
Extensions and discoveries	14,822	22,945	4,224	22,870
Revisions	(5,403)	(18,411)	(3,634)	(12,106)
Production	(4,803)	(5,865)	(1,006)	(6,786)
December 31, 2023	66,308	123,948	20,749	107,715
Proved Developed Reserves, Included Above				
December 31, 2021	27,096	47,974	7,949	43,041
December 31, 2022	29,632	59,314	9,604	49,122
December 31, 2023	36,731	71,671	11,502	60,178
Proved Undeveloped Reserves, Included Above				
December 31, 2021	19,925	29,512	5,522	30,366
December 31, 2022	19,250	26,704	4,850	28,551
December 31, 2023	29,577	52,277	9,247	47,537

As of December 31, 2023, reserves were comprised of 61.5 % oil, 19.2 % natural gas and 19.3 % NGL. 2023 proved reserves were estimated based on average realized prices of $ 76.02 per Bbl of oil, $ 0.46 per Mcf of natural gas and $ 7.11 per Bbl of NGL. Prices used in the 2023 reserve report are based on the twelve month unweighted arithmetic average of the first-day-of-the-month price for each month in the period ("SEC price") January 2023 through December 2023. For oil and NGL volumes, the average West Texas Intermediate ("WTI") SEC price of $ 78.22 per Bbl is adjusted for quality, transportation fees, and market differentials. The fees associated with the transportation contract are included as a deduction to oil revenue. For gas volumes, the average Henry Hub SEC price of $ 2.64 per MMBtu is adjusted for energy content, transportation fees and market differentials.

As of December 31, 2022, reserves were comprised of 62.9 % oil, 18.5 % natural gas and 18.6 % NGL. 2022 proved reserves were estimated based on prices of $ 91.96 per Bbl of oil, $ 3.16 per Mcf of natural gas and $ 25.55 per Bbl of NGL. Prices used in the 2022 reserve report are based on the twelve month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January 2022 through December 2022. For oil and NGL volumes, the average WTI SEC price of $ 94.14 per Bbl is adjusted for quality, transportation fees, and market differentials. The fees associated with the transportation contract are included as a deduction to oil revenue. For gas volumes, the average Henry Hub SEC price of $ 6.36 per MMBtu is adjusted for energy content, transportation fees and market differentials.

For the year ended December 31, 2023, the Company added 30.0 MMBoe of proved reserves, with such additions due to acquisitions and extensions and discoveries, partially offset by negative revisions and production. The Company had acquisitions of 26.1 MMBoe primarily as a result of the New Mexico Acquisition and extensions and discoveries to proved reserves of 22.9 MMBoe, which consisted of 8.3 MMBoe added to PDP as a result of drilling successful wells that were previously classified as unproved locations, and 14.6 MMBoe added to PUDs as a result of drilling successful wells offsetting locations that were previously unproven locations. The Company had downward revisions of previous estimates of 12.1 MMBoe, which are primarily attributable to the removal of PUDs due to changes in the Company's development schedule. Consistent with SEC guidelines, PUDs are limited to those locations that are reasonably certain to be developed within five years.

SUPPLEMENTAL OIL AND GAS INFORMATION - (continued)
(Unaudited)

For the year ended December 31, 2022, the Company had downward revisions of previous estimates of 6.3 MMBoe. These revisions are primarily the result of changes in certain well level projections and higher projected operating costs. The Company had extensions and discoveries to proved reserves of 14.8 MMBoe, which consisted of 7.8 MMBoe added to PDP as a result of drilling successful wells that were previously classified as unproved locations, and 7.0 MMBoe added to PUDs as a result of drilling successful wells offsetting locations that were previously unproven locations. During the year ended December 31, 2022, the Company did not acquire any reserves.

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

The Company follows the guidelines prescribed in ASC Topic 932 Extractive Activities – Oil and Gas for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The following summarizes the policies used in the preparation of the accompanying oil, natural gas and NGL reserve disclosures, standardized measures of discounted future net cash flows from proved oil, natural gas and NGL reserves and the reconciliations of standardized measures from year to year.

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows: (i) estimates are made of quantities of proved reserves and future periods during which they are expected to be produced based on year-end economic conditions; (ii) estimated future cash flows are compiled by applying the twelve month average of the first of the month prices of oil and natural gas relating to the Company's proved reserves to the year-end quantities of those reserves; (iii) future cash flows are reduced by estimated production costs, costs to develop and produce the proved reserves and abandonment costs, all based on year-end economic conditions, plus Company overhead incurred; (iv) future income tax expenses are based on year-end statutory tax rates giving effect to the remaining tax basis in the oil and natural gas properties, other deductions, credits and allowances relating to the Company's proved oil and natural gas reserves; and, (v) future net cash flows are discounted to present value by applying a discount rate of 10%.

The assumptions used to compute the standardized measure are those prescribed by the FASB and the SEC. These assumptions do not necessarily reflect the Company's expectations of actual revenues to be derived from those reserves, nor their present value. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these reserve quantity estimates are the basis for the valuation process. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair value of the Company's oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following summary sets forth the Company's future net cash flows relating to proved oil, natural gas and NGL reserves based on the standardized measure prescribed in ASC Topic 932:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Future crude oil, natural gas and NGLs sales [(1)(2)]	$ 5,244,927	$ 5,135,650
Future production costs	(1,896,397)	(1,559,266)
Future development costs	(362,218)	(341,481)
Future income tax expense	(538,926)	(658,340)
Future net cash flows	2,447,386	2,576,563
10% annual discount	(1,186,921)	(1,468,187)
Standardized measure of discounted future net cash flows	$ 1,260,465	$ 1,108,376

(1) December 31, 2023 proved reserves were derived based on average realized prices of $ 76.02 per barrel of oil, $ 0.46 per Mcf of natural gas and $ 7.11 per barrel of NGL.

(2) December 31, 2022 proved reserves were derived based on average realized prices of $ 91.96 per barrel of oil, $ 3.16 per Mcf of natural gas and $ 25.55 per barrel of NGL.

SUPPLEMENTAL OIL AND GAS INFORMATION - (continued)
(Unaudited)

Principal sources of change in the Standardized Measure are shown below:

	Year Ended December 31,	
	2023	2022
	(In thousands)	
Balance, beginning of period	$ 1,108,376	$ 703,469
Sales of crude oil, natural gas and NGLs, net	(288,270)	(267,612)
Net change in prices and production costs	(618,441)	406,803
Net changes in future development costs	21,423	(40,226)
Extensions and discoveries	385,482	321,009
Acquisition of reserves	613,295	—
Revisions of previous quantity estimates	(188,364)	(83,188)
Previously estimated development costs incurred	31,124	8,775
Net change in income taxes	(5,976)	(117,098)
Accretion of discount	140,115	87,914
Other	61,701	88,530
Balance, end of period	$ 1,260,465	$ 1,108,376

Exhibit 4.1

DESCRIPTION OF CAPITAL STOCK

The following is a description of the capital stock of Riley Exploration Permian, Inc. (the "Company," "we," "us," and "our") and a summary of the rights of our stockholders. This description and summary is not complete, and you should also refer to our first amended and restated certificate of incorporation ("certificate of incorporation") and third amended and restated bylaws ("bylaws"), which are incorporated by reference in and to this prospectus.

General

The Company's authorized capital stock consists of an aggregate of 265 million (265,000,000) shares, including:

- 240 million (240,000,000) shares of common stock, par value $.001 per share; and
- 25 million (25,000,000) shares of preferred stock, par value $.0001 per share.

Common Stock

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock are not entitled to vote on any amendment to the certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to our certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the Delaware General Corporation Law ("DGCL"). Subject to prior rights and preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably in proportion to the shares of common stock held by them such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable.

The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets in proportion to the shares of common stock held by them that are remaining after payment or provision for payment of all of our debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

Preferred Stock

Our certificate of incorporation authorizes our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, covering up to an aggregate of 25,000,000 shares of preferred stock. Each class or series of preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by the board of directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights.

Except as provided by law or in a preferred stock designation, the holders of preferred stock will not be entitled to vote at or receive notice of any meeting of stockholders.

Subject to our certificate of incorporation and to any limitations imposed by any then outstanding preferred stock, we may issue additional series of preferred stock, at any time or from time to time, with such powers, preferences, rights and qualifications, limitations or restrictions as our board of directors determines, and without further action of the stockholders, including holders of our then outstanding preferred stock, if any. We currently have no shares of preferred stock outstanding.

Anti-Takeover Effects of Provisions of Our Certificate of Incorporation, Our Bylaws and Delaware Law

Some provisions of Delaware law contain, and our certificate of incorporation and our bylaws contain, provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

Section 203 of the DGCL prohibits a Delaware corporation, including those whose securities are listed for trading on the NYSE American, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- 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; or
- 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.

We have elected to not be subject to the provisions of Section 203 of the DGCL in our certificate of incorporation.

Our Certificate of Incorporation and Our Bylaws

Provisions of our certificate of incorporation and our bylaws may delay or discourage transactions involving an actual or potential change in control or change in our management, including transactions in which stockholders might otherwise receive a premium for their shares, or transactions that our stockholders might otherwise deem to be in their best interests. Therefore, these provisions could adversely affect the price of our securities.

Among other things, our certificate of incorporation and bylaws include the following provisions:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders.

  These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 120 days prior to the first anniversary date of the mailing of notice of the annual meeting for the preceding year. Our bylaws will specify the requirements as to form and content of all stockholders' notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of the Company. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;

- provide that the authorized number of directors may be changed only by resolution of the board of directors;

- provide that at any time after (i) certain investment funds managed by Yorktown Partners LLC ("Yorktown"), (ii) Boomer Petroleum, LLC ("Boomer"), (iii) Bluescape Riley Exploration Acquisition, LLC ("BREA"), (iv) Bluescape Riley Exploration Holdings, LLC ("BREH" and together with BREA, "Bluescape"), and their respective affiliates, no longer collectively beneficially own more than 50% of the outstanding shares of our common stock, our bylaws can be amended by the board of directors;

- provide that, at any time after Yorktown, Boomer, Bluescape and their respective affiliates no longer collectively beneficially own more than 50% of the outstanding shares of our common stock, any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock with respect to such series (prior to such time, such actions may be taken without a meeting by written consent of holders of common stock having not less than the minimum number of votes that would be necessary to authorize such action at a meeting at which all shares entitled to vote thereon were present and voted);

- provide that, at any time after Yorktown, Boomer, Bluescape and their respective affiliates no longer collectively beneficially own more than 50% of the outstanding shares of our common stock, our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of at least two-thirds of our then outstanding common stock (prior to such time, our certificate of incorporation and bylaws may be amended by the affirmative vote of the holders of a majority of our then outstanding common stock);

- provide that we renounce any interest in existing and future investments in other entities by, or the business opportunities of, Yorktown, Boomer, Bluescape, or any of their officers, directors, agents, stockholders, members, partners, affiliates and subsidiaries (other than our directors that are presented business opportunities in their capacity as our directors) and that they have no obligation to offer us those investments or opportunities;
- provide that special meetings of our stockholders may only be called by a majority of the board of directors, the chief executive officer, or the chairman of the board; and
- provide that, at any time after Yorktown, Boomer, Bluescape, and their respective affiliates, no longer collectively beneficially own more than 50% of the outstanding shares of our common stock, the affirmative vote of the holders of at least two-thirds of the voting power of all then-outstanding common stock entitled to vote generally in the election of directors, voting together as a single class, shall be required to remove any or all of the directors from office and such removal may only be for cause (prior to such time, directors may be removed either with or without cause by the affirmative vote of holders of a majority of our outstanding stock entitled to vote).

Forum Selection

Our bylaws provide that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for:

- any derivative action or proceeding brought on our behalf;
- any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders;
- any action asserting a claim against us arising pursuant to any provision of the DGCL, our certificate of incorporation or our bylaws; or
- any action asserting a claim against us that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein.

Our bylaws also provides that unless we consent in writing to the selection of an alternative forum, the federal district courts of the United States of America will be the sole and exclusive forum for any stockholder to bring a complaint asserting a cause of action under the Securities Act of 1933, as amended or the Securities Exchange Act of 1934, as amended.

Our bylaws also provide that any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and to have consented to, this forum selection 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 our directors, officers, employees and agents. The enforceability of similar exclusive forum provisions in other companies' certificates of incorporation or bylaws has been challenged in legal proceedings, and it is possible that, in connection with one or more actions or proceedings described above, a court could rule that this provision in our bylaws is inapplicable or unenforceable.

Listing

Our common stock is listed and traded on the NYSE American under the symbol "REPX."

Transfer Agent and Registrar

The transfer agent and registrar for our securities is Continental Stock Transfer & Trust Company with a mailing address of 1 State Street, 30th Floor, New York, NY 10004-1561 and with a phone number of (212) 509-4000.

Exhibit 21.1

Riley Exploration Permian, Inc.
Subsidiaries

Name of Subsidiary	State of Formation
Riley Exploration – Permian, LLC	DE
Riley Permian Operating Company, LLC	DE
RPC Power HoldCo LLC	DE

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-255104) and Form S-8 (Nos. 333-253750 and 333-271415) of Riley Exploration Permian, Inc. of our reports dated March 6, 2024, relating to the consolidated financial statements, and the effectiveness of Riley Exploration Permian, Inc.'s internal control over financial reporting, which appear in this Annual Report on Form 10-K.

/s/ BDO USA, P.C.
Houston, Texas
March 6, 2024

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion in this Annual Report on Form 10-K of Riley Exploration Permian, Inc. for the year ended December 31, 2023, of our report dated January 25, 2024, with respect to estimates of reserves and future net revenue of Riley Exploration Permian, Inc., as of December 31, 2023, as well as to the incorporation by reference in the Registration Statements on Form S-3 (No. 333-255104) and Form S-8 (No. 333-253750 and No. 333-271415) of Riley Exploration Permian, Inc.

Ryder Scott Company

By: /s/ Ryder Scott Company, LP

Ryder Scott Company, LP

Denver, Colorado
March 6, 2024

Exhibit 31.1

CERTIFICATION

I, Bobby D. Riley, certify that:

1. I have reviewed this Annual Report on Form 10-K of Riley Exploration Permian, Inc. for the year ended December 31, 2023.

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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Dated:	March 6, 2024
By:	/s/ Bobby D. Riley
	Bobby D. Riley
	Chief Executive Officer

Exhibit 31.2

CERTIFICATION

I, Philip Riley, certify that:

1. I have reviewed this Annual Report on Form 10-K of Riley Exploration Permian, Inc. for the year ended December 31, 2023.

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 officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

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

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

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

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

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

Dated:	March 6, 2024
By:	/s/ Philip Riley
	Philip Riley
	Chief Financial Officer

Exhibit 32.1

CERTIFICATION

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 I hereby certify that:

I have reviewed the Annual Report on Form 10-K of Riley Exploration Permian, Inc. (the “Company”) for the year ended December 31, 2023 (the “Report”).

To the best of my knowledge the Report (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m (a) or 78o (d)); and, (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated:	March 6, 2024
By:	/s/ Bobby D. Riley
	Bobby D. Riley
	Chief Executive Officer

Exhibit 32.2

CERTIFICATION

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 I hereby certify that:

I have reviewed the Annual Report on Form 10-K of Riley Exploration Permian, Inc. (the “Company”) for the year ended December 31, 2023 (the “Report”).

To the best of my knowledge the Report (i) fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m (a) or 78o (d)); and, (ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated:	March 6, 2024
By:	/s/ Philip Riley
	Philip Riley
	Chief Financial Officer

Exhibit 97.1

Riley Exploration Permian, Inc.
Clawback policy

EFFECTIVE DECEMBER 1, 2023

1. Purpose. The purpose of this Riley Exploration Permian, Inc. (the "Company") Clawback Policy (this "Policy") is to enable the Company to recover Erroneously Awarded Compensation from Covered Executive Officers in the event that the Company is required to prepare an Accounting Restatement. This Policy is designed to comply with, and shall be interpreted to be consistent with, Section 954 of the Dodd- Frank Wall Street Reform and Consumer Protection Act of 2010, as codified in Section 10D of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), Rule 10D-1 promulgated under the Exchange Act ("Rule 10D-1"), Section 303A.14 of the New York Stock Exchange (the "NYSE") Listed Company Manual and Section 811 of NYSE American Company Guide (the "Listing Standards"). Unless otherwise defined in this Policy, capitalized terms shall have the meaning ascribed to such terms in Section 2.

2. Definitions. As used in this Policy, the following capitalized terms shall have the meanings set forth below.

   a. "Accounting Restatement" means an accounting restatement of the Company's financial statements due to the Company's material noncompliance with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements (i.e., a "Big R" restatement), or to correct an error that is not material to the previously issued financial statements, but that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (i.e., a "little r" restatement).

   b. "Accounting Restatement Date" means the earlier to occur of (i) the date the Board, a Committee of the Board, or the officer or officers of the Company authorized to take such action if the Board's or Committee's action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement and (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare an Accounting Restatement.

   c. "Applicable Period" means, with respect to any Accounting Restatement, the three completed fiscal years immediately preceding the Accounting Restatement Date, as well as any transition period (that results from a change in the Company's fiscal year) within or immediately following those three completed fiscal years (except that a transition period that comprises a period of at least nine months shall count as a completed fiscal year).

   d. "Board" means the board of directors of the Company.

e. "Code" means the U.S. Internal Revenue Code of 1986, as amended. Any reference to a section of the Code or regulation thereunder includes such section or regulation, any valid regulation or other official guidance promulgated under such section, and any comparable provision of any future legislation or regulation amending, supplementing, or superseding such section or regulation.

f. "Covered Executive Officer" means an individual who is currently or previously served as the Company's principal executive officer, president, principal financial officer, principal accounting officer (or, if there is no such accounting officer, the controller), vice president of the Company in charge of a principal business unit, division, or function (such as sales, administration, or finance), an officer who performs (or performed) a policy-making function, or any other person who performs (or performed) similar policy-making functions for the Company or is otherwise determined to be an executive officer of the Company pursuant to Item 401(b) of Regulation S-K. An executive officer of the Company's parent or subsidiary is deemed a "Covered Executive Officer" if the executive officer performs (or performed) such policy- making functions for the Company.

g. "Erroneously Awarded Compensation" means, in the event of an Accounting Restatement, the amount of Incentive-Based Compensation previously received that exceeds the amount of Incentive-Based Compensation that otherwise would have been received had it been determined based on the restated amounts in such Accounting Restatement, and must be computed without regard to any taxes paid by the relevant Covered Executive Officer; provided, however, that for Incentive- Based Compensation based on stock price or total stockholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in an Accounting Restatement:
(i) the amount of Erroneously Awarded Compensation must be based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or total stockholder return upon which the Incentive-Based Compensation was received and (ii) the Company must maintain documentation of the determination of that reasonable estimate and provide such documentation to the NYSE American.

h. "Financial Reporting Measure" means any measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements and any measure that is derived wholly or in part from such measure. Stock price and total stockholder return are also Financial Reporting Measures. A Financial Reporting Measure is not required to be presented within the Company's financial statements or included in a filing with the

U.S. Securities and Exchange Commission to qualify as a “Financial Reporting Measure.”

i. “Incentive-Based Compensation” means any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting

Measure. Incentive-Based Compensation is deemed “received” for purposes of this Policy in the Company’s fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of such Incentive-Based Compensation occurs after the end of that period.

3. Administration. This Policy shall be administered by the Board, the Compensation Committee of the Board (the “Compensation Committee”), the Audit Committee of the Board (the “Audit Committee”) or a special committee comprised of members of the Compensation Committee and Audit Committee.

For purposes of this Policy, the body charged with administering this Policy shall be referred to herein as the Administrator.” The Administrator is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate or advisable for the administration of this Policy, in each case, to the extent permitted under the Listing Standards and in compliance with (or pursuant to an exemption from the application of) Section 409A of the Code. All determinations and decisions made by the Administrator pursuant to the provisions of this Policy shall be final, conclusive and binding on all persons, including the Company, its affiliates, its stockholders and Covered Executive Officers, and need not be uniform with respect to each person covered by this Policy.

In the administration of this Policy, the Administrator is authorized and directed to consult with the full Board or such other Committees of the Board as may be necessary or appropriate as to matters within the scope of such other Committee’s responsibility and authority. Subject to any limitation at applicable law, the Administrator may authorize and empower anyofficer or employee of the Companyto take anyand all actions necessary or appropriate to carry out the purpose and intent of this Policy (other than with respect to any recovery under this Policy involving such officer or employee). Any action or inaction by the Administrator withrespect to a Covered Executive Officer underthis Policy in no waylimitsthe Administrator’sdecisionto act or not to act withrespect to anyother Covered Executive Officerunder this Policy or underanysimilar policy, agreement or arrangement, nor shall any such action or inaction serve as a waiver of any rights the Company may have against any Covered Executive Officer other than as set forth in this Policy.

4. Application of this Policy. This Policy applies to all Incentive-Based Compensation received by a person: (a) after beginning service as a Covered Executive Officer; (b) who served as a Covered Executive Officer at any time during the performance period for such Incentive-Based Compensation; (c) while the Company had a listed class of securities on a national securities exchange; and (d) during the Applicable Period. For the avoidance of doubt, Incentive-Based Compensation that is subject to both a Financial Reporting Measure vesting condition and a service-based vesting condition shall be considered received when the relevant Financial Reporting Measure is achieved, even if the Incentive-Based Compensation continues to be subject to the service-based vesting condition.

5. Recovery Erroneously Awarded Compensation. In the event of an Accounting Restatement, the Company must recover Erroneously Awarded Compensation reasonably promptly, in amounts determined pursuant to this Policy. The Company's obligation to recover Erroneously Awarded Compensation is not dependent on the filing of restated financial statements. Recovery under this Policy with respect to a Covered Executive Officer shall not require the finding of any misconduct by such Covered Executive Officer or such Covered Executive Officer being found responsible for the accounting error leading to an Accounting Restatement. In the event of an Accounting Restatement, the method for recouping Erroneously Awarded Compensation shall be determined by the Administrator in its sole and absolute discretion, to the extent permitted under the Listing Standards and in compliance with (or pursuant to an exemption from the application of) Section 409A of the Code. Recovery may include, without limitation, (i) reimbursement of all or a portion of any incentive compensation award, (ii) cancellation of incentive compensation awards and (iii) any other method authorized by applicable law or contract.

The Company is authorized and directed pursuant to this Policy to recover Erroneously Awarded Compensation in compliance with this Policy unless the Compensation Committee has determined that recovery would be impracticable solely for the following limited reasons, and subject to the following procedural and disclosure requirements:

a. The direct expenses paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered. Before reaching such conclusion, the Administrator must make a reasonable attempt to recover such Erroneously Awarded Compensation, document such reasonable attempt(s) to recover, and provide that documentation to the NYSE American;

a. Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Code.

6. Prohibition on Indemnification and Insurance Reimbursement. The Company is prohibited from indemnifying any Covered Executive Officer against the loss of any Erroneously Awarded Compensation. Further, the Company is prohibited from paying or reimbursing a Covered Executive Officer for the cost of purchasing insurance to cover any such loss. The Company is also prohibited from entering into any agreement or arrangement whereby this Policy would not apply or fail to be enforced against a Covered Executive Officer.

7. Required Policy-Related Disclosure and Filings. The Company shall file all disclosures with respect to this Policy in accordance with the requirements of the federal securities laws, including disclosures required by U.S. Securities and Exchange Commission filings. A copy of this Policy and any amendments hereto shall be posted on the Company's website and filed as an exhibit to the Company's annual report on Form 10-K.

8. Acknowledgement. Each Covered Executive Officer shall sign and return to the Company within thirty (30) calendar days following the later of (i) the effective date of

this Policy set forth below or (ii) the date such individual becomes a Covered Executive Officer, the Acknowledgement Form attached hereto as **Exhibit A**, pursuant to which the Covered Executive Officer agrees to be bound by, and to comply with, the terms and conditions of this Policy.

9. Amendment; Termination. The Board may amend this Policy from time to time in its sole and absolute discretion and shall amend this Policy as it deems necessary to reflect the Listing Standards or to comply with (or maintain an exemption from the application of) Section 409A of the Code. The Board may terminate this Policy at any time; provided, that the termination of this Policy would not cause the Company to violate any federal securities laws, or rules promulgated by the U.S. Securities and Exchange Commission or the Listing Standards.

10. Other Recovery Obligations; General Rights. The Board intends that this Policy shall be applied to the fullest extent of the law. To the extent that the application of this Policy would provide for recovery of Incentive- Based Compensation that the Company already recovered pursuant to Section 304 of the Sarbanes-Oxley Act or other recovery obligations, any such amount recovered from a Covered Executive Officer will be credited to any recovery required under this Policy in respect of such Covered Executive Officer.

11. Effective Date. This Policy shall be effective as of December 1, 2023. The terms of this Policy shall apply to any Incentive- Based Compensation that is received by Covered Executive Officers on or after October 2, 2023, even if such Incentive-Based Compensation was approved, awarded or granted to Covered Executive Officers prior to such date.

12. Cumulative Remedies. This Policy shall not limit the rights of the Company to take any other actions or pursue other remedies that the Company may deem appropriate under the circumstances and under applicable law, in each case, to the extent permitted under the Listing Standards and in compliance with (or pursuant to an exemption from the application of) Section 409A of the Code.

13. Binding Effect. This Policy is binding and enforceable against all Covered Executive Officers and their beneficiaries, heirs, executors, administrators or other legal representative.

Riley Exploration Permian, Inc.

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2023

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President

COLORADO REGISTERED PROFESSIONAL ENGINEER
SCOTT JAMES WILSON
36112
1/25/2024

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 1700 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

January 25, 2024

Riley Exploration Permian, Inc.
29 E. Reno Ave, STE 500
Oklahoma City, Oklahoma 73104

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold and royalty interests of Riley Exploration Permian, Inc. (Riley) as of December 31, 2023. The subject properties are located in the states of New Mexico and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on January 25, 2024 and presented herein, was prepared for public disclosure by Riley in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott account for all of the proved net liquid hydrocarbon reserves and all the proved net gas reserves of Riley as of December 31, 2023.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2023, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the "as of date" of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
Riley Exploration Permian, Inc.
As of December 31, 2023

	Proved			
	Developed			Total
	Producing	Non-Producing*	Undeveloped	Proved
Net Reserves				
Oil/Condensate – MBarrels	36,731	0	29,577	66,308
Plant Products – MBarrels	11,502	0	9,247	20,749
Gas – MMCF	71,671	0	52,277	123,948
Income Data ($M)				
Future Gross Revenue	$2,735,046	$0	$2,219,795	$4,954,841
Deductions	1,088,400	9,583	870,597	1,968,580
Future Net Income (FNI)	$1,646,646	($9,583)	$1,349,198	$2,986,261
Discounted FNI @ 10%	$ 928,039	($8,740)	$ 664,755	$1,584,054

*Negative values of Future Net Income (FNI) and Discounted FNI in the Non-Producing reserves category are due to abandonment costs.

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (MBarrels). All gas volumes are reported on an “as sold basis” expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of Riley. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist, nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 99 percent and gas reserves account for the remaining 1 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates, which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income ($M) As of December 31, 2023 Total Proved
5	$2,081,225
15	$1,274,561
20	$1,065,057
25	$ 914,631

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing category has no reserves and consists of the shut-in status category. It is included here only to capture certain abandonment expenses.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as 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." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends primarily on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Riley's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

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." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Riley's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which Riley owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods, which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely to be achieved than not." The SEC states that "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." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved reserves for the properties included herein were estimated by performance methods, the volumetric method, analogy, or a combination of methods. All of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, material balance and/or reservoir simulation which utilized extrapolations of historical production and pressure data available through October 2023 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by Riley or obtained from public data sources and were considered sufficient for the purpose thereof.

All of the proved undeveloped reserves included herein were estimated by the volumetric method, analogy, or a combination of methods. The volumetric analysis utilized pertinent well and seismic data furnished to Ryder Scott by Riley or which we have obtained from public data sources that were available through October 2023. The data utilized from the analogues in conjunction with the well and seismic data were considered sufficient for the purpose thereof.

To estimate economically producible proved oil and 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 anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Riley has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by Riley with respect to property interests owned, 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, ad valorem and production taxes, development costs, development plans, product prices based on the SEC regulations, adjustments or differentials to product prices, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Riley. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Riley. Locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements.

Riley furnished us with the above mentioned average benchmark prices in effect on December 31, 2023. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by Riley. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by Riley to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the "average realized prices." The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
	Oil/Condensate	WTI Cushing	$78.22/BBL	$76.02/BBL
	Plant Products	WTI Cushing	$78.22/BBL	$7.11/BBL
	Gas	Henry Hub	$2.637/MMBTU	$0.46/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Riley and are based on the operating expense reports of Riley and include only those costs directly applicable to the leases or wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Riley. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Riley and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. Riley's estimates of abandonment costs after salvage value are shown in the Other Deductions Column and were used at Riley's request. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Riley's estimates.

The proved undeveloped reserves in this report have been incorporated herein in accordance with Riley's plans to develop these reserves as of December 31, 2023. The implementation of Riley's development plans as presented to us and incorporated herein is subject to the approval process adopted by Riley's management. As the result of our inquiries during the course of preparing this report, Riley has informed us that the development activities included herein have been subjected to and received the internal approvals required by Riley's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Riley. Riley has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, Riley has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2023, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Riley were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists receive professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Riley. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Riley.

Riley makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, Riley has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Forms S-3 and S-8 of Riley, of the references to our name, as well as to the references to our third party report for Riley, which appears in the December

31, 2023 annual report on Form 10-K of Riley. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Riley.

We have provided Riley with a digital version of the original signed copy retained in our files. In the event there are any differences between the digital version included in filings made by Riley and the original signed copy in our files, the original signed file copy shall control and supersede.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPELS Firm Registration No. F-1580

Scott J. Wilson, P.E., MBA
Colorado License No. 36112
Senior Vice President

COLORADO REGISTERED
SCOTT JAMES WILSON
36112
1/25/2024
PROFESSIONAL ENGINEER

SJW (HGA)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Scott James Wilson was the primary technical person responsible for the estimate of the reserves, future production, and income presented herein.

Mr. Wilson, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2000, is a Senior Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Wilson served in a number of engineering positions with Atlantic Richfield Company. For more information regarding Mr. Wilson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/company/employees/denver-employees.

Mr. Wilson earned a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines in 1983 and an MBA in Finance from the University of Colorado in 1985, graduating from both with High Honors. He is a registered Professional Engineer by exam in the States of Alaska, Colorado, Texas, and Wyoming. He is also an active member of the Society of Petroleum Engineers; serving as co-Chairman of the SPE Reserves and Economics Technology Interest Group, and Gas Technology Editor for SPE's Journal of Petroleum Technology. He is a member and past chairman of the Denver section of the Society of Petroleum Evaluation Engineers. Mr. Wilson has published several technical papers, one chapter in Marine and Petroleum Geology and two in SPEE monograph 4, which was published in 2016. He is the primary inventor on four US patents and won the 2017 Reservoir Description and Dynamics award for the SPE Rocky Mountain Region.

In addition to gaining experience and competency through prior work experience, several state Boards of Professional Engineers require a minimum number of hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Wilson fulfills as part of his registration in four states. As part of his continuing education, Mr. Wilson attends internally presented training as well as public forums relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, and Final Rule released January 14, 2009 in the Federal Register. Mr. Wilson attends additional hours of formalized external training covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering and petroleum economics evaluation methods, procedures and software and ethics for consultants.

Based on his educational background, professional training and more than 35 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Wilson has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the "Modernization of Oil and Gas Reporting; Final Rule" in the Federal Register of National Archives and Records Administration (NARA). The "Modernization of Oil and Gas Reporting; Final Rule" includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The "Modernization of Oil and Gas Reporting; Final Rule", including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the "SEC regulations". The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

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. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

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).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

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

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

> (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
>
> (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

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.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are 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
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
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
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.

UNDEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

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

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

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.