

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

FORM 10-K

(Mark One)

- ☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2023
Or
☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period From _____ to _____.
is Commission File Number 0-7406

PrimeEnergy Resources Corporation
(Exact name of registrant as specified in its charter)

Delaware
(state or other jurisdiction of incorporation or organization)

84-0637348
(I.R.S. Employer Identification No.)

9821 Katy Freeway , Houston , Texas
(Address of principal executive offices)

77024
(Zip Code)

Registrant's telephone number, including area code: (713) 735-0000

Securities registered pursuant to Section 12(g) of the Act

<u>Title of each class</u>	<u>Trading Symbol</u>	<u>Name of each Exchange on which registered</u>
Common Stock, par value \$0.10 (per share)	PNRG	Nasdaq Stock Market

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒
Indicate whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.
Large Accelerated Filer ☐ Accelerated Filer ☐
Non-Accelerated Filer ☒ Smaller Reporting Company ☒
Emerging growth company ☐

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

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

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

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

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

Auditor PCAOB ID Number: 606 Auditor Name: Grassi & Co., CPAs, P.C. Auditor Location: New York, NY

The aggregate market value of the voting stock of the registrant held by non-affiliates, computed by reference to the average bid and asked price of such common equity as of the last business day of the registrant's most recently completed second fiscal quarter, was \$ 65,081,697 .

The number of shares outstanding of the registrant's Common Stock, par value \$0.10 per share, as of April 15, 2024, was 1,790,245 .

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's proxy statement to be furnished to stockholders in connection with its Annual Meeting of Stockholders to be held on June 5, 2024, are incorporated by reference in Part III hereof.

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Definitions of Certain Terms and Conventions Used Herein

Within this Report, the following terms and conventions have specific meanings:

Measurements.

- **“Bbl”** means a standard barrel containing 42 United States gallons.
- **“BOE”** means a barrel of oil equivalent and is a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of six thousand cubic feet of gas to one Bbl of oil or natural gas liquid.
- **“BOEPD”** means BOE per day.
- **“Btu”** means British thermal unit, which is a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
- **“MBbl”** means one thousand Bbls.
- **“MBOE”** means one thousand BOEs.
- **“Mcf”** means one thousand cubic feet and is a measure of gas volume.
- **“MMcf”** means one million cubic feet.

Indices.

- **“Brent”** means Brent oil price, a major trading classification of light sweet oil that serves as a benchmark price for oil worldwide.
- **“WAHA”** is a benchmark pricing hub for West Texas gas.
- **“WTI”** means West Texas Intermediate, a light sweet blend of oil produced from fields in western Texas and is a grade of oil used as a benchmark in oil pricing. General terms and conventions.
- **“DD&A”** means depletion, depreciation and amortization.
- **“ESG”** means environmental, social and governance.
- **“GAAP”** means accounting principles generally accepted in the United States of America.
- **“GHG”** means greenhouse gases.
- **“LNG”** means liquefied natural gas.
- **“NGLs”** means natural gas liquids, which are the heavier hydrocarbon liquids that are separated from the gas stream; such liquids include ethane, propane, isobutane, normal butane and natural gasoline.
- **“NYMEX”** means the New York Mercantile Exchange.
- **“OPEC”** means the Organization of Petroleum Exporting Countries.
- **“PrimeEnergy”** or the “Company” means PrimeEnergy Resources Corporation and its subsidiaries.
- **“Proved developed reserves”** means reserves that can be expected to be recovered 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.
- **“Proved reserves”** means those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
 - (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 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 elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.
 - (iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.
 - (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average during the 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.
- **"Proved undeveloped reserves"** means reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for 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 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.
 - (iii) 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.
 - **"SEC"** means the United States Securities and Exchange Commission.
 - **"Standardized Measure"** means the after-tax present value of estimated future net cash flows of proved reserves, determined in accordance with the rules and regulations of the SEC, using prices and costs employed in the determination of proved reserves and a 10 percent discount rate.
 - **"U.S."** means United States.
 - With respect to information on the working interest in wells, drilling locations and acreage, "**net**" wells, drilling locations and acres are determined by multiplying "**gross**" wells, drilling locations and acres by the Company's working interest in such wells, drilling locations or acres. Unless otherwise specified, wells, drilling locations and acreage statistics quoted herein represent gross wells, drilling locations or acres.
 - **"WASP"** means weighted average sales price.
 - All currency amounts are expressed in U.S. dollars.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This information in this Annual Report on Form 10-K (this "Report") contains forward-looking statements that involve risks and uncertainties. When used in this document, the words "believes," "plans," "expects," "anticipates," "forecasts," "models," "intends," "continue," "may," "will," "could," "should," "future," "potential," "estimate," or the negative of such terms and similar expressions as they relate to the Company are intended to identify forward-looking statements, which are generally not historical in nature. The forward-looking statements are based on PrimeEnergy Resources Corporation "The Company" current expectations, assumptions, estimates and projections about the Company and the industry in which the Company operates. Although the Company believes that the expectations and assumptions reflected in the forward-looking statements are reasonable as and when made, they involve risks and uncertainties that are difficult to predict and, in many cases, beyond the Company's control. In addition, the Company may be subject to currently unforeseen risks that may have a material adverse effect on it.

These risks and uncertainties include, among other things, volatility of commodity prices; product supply and demand; the impact of armed conflict (including the conflicts in Ukraine and the Middle East) or political instability on economic activity and oil and gas supply and demand; competition; the ability to obtain drilling, environmental and other permits and the timing thereof; the effect of future regulatory or legislative actions on The Company or the industry in which it operates, including potential changes to tax rates or laws, new restrictions on development activities or potential changes in regulations limiting produced water disposal; the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms; potential liability resulting from pending or future litigation; the costs, including the potential impact of cost increases due to inflation and supply chain disruptions, and results of development and operating activities; the impact of a widespread outbreak of an illness on global and U.S. economic activity, oil and gas demand, and global and U.S. supply chains; availability of equipment, services, resources and personnel required to perform the Company's development and operating activities; access to and availability of transportation, processing, fractionation, refining, storage and export facilities; The Company's ability to replace reserves, implement its business plans or complete its development activities as scheduled; the Company's ability to achieve its emissions reductions, flaring and other ESG goals; access to and cost of capital; the financial strength of (i) counterparties to The Company's credit facility and derivative contracts, (ii) issuers of The Company's investment securities and (iii) purchasers of The Company's oil, NGL and gas production and downstream sales of purchased commodities; uncertainties about estimates of reserves, identification of drilling locations and the ability to add proved reserves in the future; the assumptions underlying forecasts, including forecasts of production, operating cash flow, well costs, capital expenditures, rates of return, expenses, and cash flow from downstream purchases and sales of oil and gas, net of firm transportation commitments; quality of technical data; environmental and weather risks, including the possible impacts of climate change on the Company's operations and demand for its products; cybersecurity risks; the risks associated with the ownership and operation of the Company's well services business and acts of war or terrorism. In addition, the Company may be subject to currently unforeseen risks that may have a materially adverse effect on it.

Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. See "Part I, Item 1. Business — Competition," "Part I, Item 1. Business — Regulation," "Part I, Item 1A. Risk Factors," "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk" in this Report for a description of various factors that could materially affect the ability of to achieve the anticipated results described in the forward-looking statements. Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. The Company undertakes no duty to publicly update these statements except as required by law.

PrimeEnergy Resources Corporation

**FORM 10-K ANNUAL REPORT
For the Fiscal Year Ended
December 31, 2023**

PART I

Item 1. BUSINESS.

General

PrimeEnergy Resources Corporation (the "Company") was organized in March 1973, under the laws of the State of Delaware. We are an independent oil and natural gas company engaged in acquiring, developing, and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, and Oklahoma. All of our oil and gas properties and interests are located in the United States. Through our subsidiaries Prime Operating Company, Eastern Oil Well Service Company, and EOWS Midland Company, we act as operator and provide well-servicing support operations for many of the onshore oil and gas wells we operate, as well as for third parties. We are also active in the acquisition of producing oil and gas properties through joint ventures with industry partners. In addition, we own a 12.5% overriding royalty interest in over 30,000 acres in the state of West Virginia. We are currently not receiving revenue from this asset, as development has not begun. In addition, through a wholly owned offshore company, we own a 60-mile-long pipeline offshore on the shallow shelf of Texas, not currently in use. We also hold a 33.3% interest in a limited partnership that owns a 138,000-square-foot retail shopping center on ten acres in Prattville, Alabama, which is on our books for \$40,000 as of December 31, 2023. There is currently no debt on the shopping center and it has approximately \$500,000 of working capital on its balance sheet.

Additional Information

PrimeEnergy files or furnishes annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934 (the "Exchange Act"). The SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, including PrimeEnergy, that file electronically with the SEC.

The Company makes available, free of charge, through its website (www.primeenergy.com) its Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after it electronically files such material with, or furnishes it to, the SEC. In addition to the reports filed or furnished with the SEC, the Company publicly discloses information from time to time in its press releases. Such information, including information posted on or connected to the Company's website, is not a part of, or incorporated by reference in, this Report or any other document the Company files with or furnishes to the SEC.

Information contained on the Company's website is not part of or incorporated into this Report or any other filings with the SEC.

Exploration, Development, and Recent Activities

The Company's activities include development and exploratory drilling. Our strategy is to develop the Company's extensive oil and gas reserves primarily through horizontal drilling. This strategy includes targeting reservoirs with high initial production rates and cash flow as well as targeting reservoirs with lower initial production rates but with higher expected return on investment. We believe that with today's technology, horizontal development of our reserves provides superior economic results as compared to vertical development, by delivering higher production rates through greater contact and stimulation of a larger volume of reservoir rock while minimizing the surface footprint required to develop those same reserves.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. In 2024, we will continue our focus on preserving financial flexibility and liquidity as we manage the risks facing our industry. Our capital budget for the year is reflective of current commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity, we may adjust our capital program throughout the year, divest non-strategic assets, or enter into strategic joint ventures.

Horizontal development of our leasehold acreage is continuing at a fast pace, particularly in West Texas, where in 2023 we participated with Double Eagle, Apache, Civitas, and ConocoPhillips in the drilling and completion of 32 new horizontal wells and in 2024 are on track to complete 54 new horizontals. In Oklahoma, in 2023, we participated with Oviniv MidContinent with a minor interest in three 3-mile-long horizontal laterals. Now, in the first quarter of 2024, we are participating with Double Eagle in 20 wells and with Civitas in 14 wells located in Reagan County, Texas. These 34 new horizontals are in the process of being drilled or are already being fracture-stimulated, and we have additional new-drills slated for drilling later in 2024. The following is a detailed description of the recent, current, and expected near-term drilling activities.

In 2023, the Company participated with five operators in the drilling and completion of 35 horizontal wells: 32 of these are located in West Texas and three in Oklahoma. In total, including the cost of facilities, the Company invested approximately \$91 million, 99% of which is attributable to the wells in West Texas where we have been drilling horizontal wells targeting various proven pay intervals in the Wolfcamp and Spraberry formations.

In Reagan County, in 2023, we participated with Hibernia Energy II (Now Civitas) in ten 2-mile-long horizontals having 25% interest and investing \$25.6 million in our "Brynn" wells that began production in April 2023. Also in Reagan County, we participated with DE IV, LLC (Double Eagle) in 15 horizontals: five 2-mile-long laterals in which we have nearly 50% interest, called the "Prime East" wells that were placed on production in May 2023, another six 2-mile-long laterals in which we have 7% interest, our "Studley AV" wells, that were brought on production in December 2023, and four 2.5-mile laterals with 20% interest, part of our "Studley CKO" wells, that were completed in December 2023 but not put online until January 2024. All twelve Studley CKO wells were brought on production in January 2024 and were therefore included in the 2023 year-end reserve report as proved developed non-producing.

Also in 2023, in Upton County, Texas we participated for 50% interest in two 3-mile-long horizontals operated by Apache. These wells were brought into production in October 2023 and we invested approximately \$17 million in these wells and their associated facilities. In Martin County, Texas we participated with ConocoPhillips for 20.8% interest in five 2.5-mile-long horizontal laterals, investing approximately \$12 million. These five wells were completed and brought online in September 2023. Also in 2023, in Oklahoma, the Company joined Oviniv USA, Inc. in the drilling of three 3-mile-long horizontals located in Canadian County with 2% interest, invested approximately \$645,000.

In the first quarter of 2024, in Reagan County, Texas, we have completed eight "Studley CKO" 2.5-mile horizontals with an average 19.7% interest, investing \$15.5 million. We are also participating in another 34 horizontal wells that are actively drilling or in the process of being stimulated. Of these 34 wells, twenty are operated by Double Eagle: the "Prime West", "Pink Floyd", "Kramer", and "O'Bannion" wells. In the six Prime West wells we have 50% interest and will invest \$24 million, in the 12 Kramer and O'Bannion wells we have an average 8.3% interest and are investing approximately \$9.9 million, and in the two Pink Floyd wells we have less than 1% interest and will invest approximately \$175,500. With Civitas, we are currently drilling 14 "Christi" wells in Reagan County, Texas, with an average of 39% interest and expect to invest \$43 million. Fourteen of the 34 wells now drilling are 2.5-mile-long laterals, while 20 are 2-mile-long laterals. All 34 are expected to be on production in the second quarter of 2024. Additionally, we have 12 horizontals slated to begin drilling in the second quarter of 2024 and be on production in the third quarter of 2024.

In 2024, we expect to complete 54 new horizontal wells, investing approximately \$140 million. We are also preparing to invest approximately \$95 million in another 23 horizontal wells to be drilled and completed in 2025. In addition, we have identified 28 horizontal locations for future development in West Texas that we anticipate to be drilled in the 2026-2027 timeframe and would require a net investment of approximately \$67 million. In total, we are planning to invest in excess of \$300 million in horizontal development in West Texas over the next several years.

In the Permian Basin of West Texas and eastern New Mexico we maintain an acreage position of approximately 16,407 gross (9,341 net) acres, 96.4% of which is located in Reagan, Upton, and Martin counties of Texas where our current West Texas horizontal drilling activities are focused. In addition to the wells currently being drilled or completed, we believe this acreage has the resource potential to support the drilling of as many as 190 future horizontal wells.

In Oklahoma, we are focused on the development of our reserves in Canadian, Grady, Kingfisher, Garfield, Major, and Garvin counties where we have approximately 4,113 net leasehold acres in the Scoop/Stack Play. Of this acreage, we believe 2,355 net leasehold acres hold significant additional resource potential that could support the drilling of as many as 43 new horizontal wells based on an estimate of four wells per multi-section drilling unit, two in the Mississippian and two in the Woodford Shale. Proposals may be received on the remaining 2,017 acres, however, rather than participate we may choose to sell the acreage or farm-out, receiving cash and retaining an over-riding royalty interest. In regard to 13 newly drilled wells in 2023, we chose to farm-out our interest and own an over-riding-royalty interest in these wells.

Significant Activity

As of December 31, 2023, we had net capitalized costs related to proved oil and gas properties of \$252.9 million. Total expenditures for the acquisition, exploration, and development of our properties during 2023 were \$113.8 million as we continue development under the programs discussed above. Proved reserves as of December 31, 2023, were 29,046 MBOE which consisted of 47% proved developed reserves and 53% proved undeveloped reserves.

The Company is actively participating in 34 horizontals that targeted the West Texas Spraberry and Wolfcamp producing intervals. In total, the Company will invest approximately \$96 million in these wells that are expected to be in production in the second quarter of 2024. Additional development on these same leasehold blocks and adjacent Company owned blocks is anticipated in the second half of 2024 and in 2025.

In 2023, the Company sold acreage for proceeds of approximately \$8 million, and acquired acreage for future development at an expense of \$2.3 million. Please see Note 2. Acquisitions and Dispositions of Notes to the Consolidated Financial Statements, included elsewhere in this Report, for details.

We believe that our diversified portfolio approach to our drilling activities produces more consistent and predictable economic results than would otherwise be experienced with a less diversified or higher-risk drilling program profile.

We attempt to assume the position of operator in all acquisitions of producing properties. We will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests and are actively pursuing the acquisition of producing properties. To diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income-producing assets to increase our net worth and increase our oil and gas reserve base.

We presently own producing and non-producing properties located primarily in Texas, and Oklahoma, and we own a substantial amount of well-servicing equipment.

We do not own any refinery or marketing facilities and do not currently own or lease any bulk storage facilities or pipelines other than adjacent to and used in connection with producing wells and the interests in certain gas gathering systems. All of our oil and gas properties and interests are located in the United States.

In the past, the supply of gas has exceeded demand on a cyclical basis, and we are subject to a combination of shut-ins and/or reduced takes of gas production during summer months. Prolonged shut-ins could result in reduced field operating income from properties in which we act as operator.

Exploration for oil and gas requires substantial expenditures, particularly in exploratory drilling in undeveloped areas, or "wildcat drilling." As is customary in the oil and gas industry, substantially all of our exploration and development activities are conducted through joint drilling and operating agreements with others engaged in the oil and gas business.

Summaries of our oil and gas drilling activities, oil and gas production, and undeveloped leasehold, mineral, and royalty interests are set forth under Item 2., "Properties", below. Summaries of our oil and gas reserves, future net revenue and present value of future net revenue are also set forth under Item 2., "Properties—Reserves", below.

Well Operations

Our operations are conducted through our principal offices in Houston, Texas, and district offices in Houston and Midland, Texas, and Oklahoma City, Oklahoma. We currently operate 542 wells, including producing, saltwater disposal, injection, and supply wells: 33 through the Houston office, 342 through the Midland office, and 167 through the Oklahoma City office. We own a majority interest in nearly all of our operated wells.

We operate wells according to operating agreements that govern the relationship between us, as operator, and the other owners of working interests in the properties and joint venture participants. For each operated well, we receive monthly fees that are competitive in the areas of operations and we also are reimbursed for expenses incurred in connection with well operations.

Regulation

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress ("Congress"), state governments, the Federal Energy Regulatory Commission (the "FERC") and other federal and state regulatory agencies and federal, state and local courts. We cannot predict when or whether any such proposals may become effective. We do not believe that such action or proposal would have a material disproportionate effect on us as compared to similarly situated competitors.

Regulation Affecting Production

Natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. In addition, all of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including 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 and the abandonment of wells. Our 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 that 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 or flaring of natural gas and impose certain requirements regarding the ratable or fair apportionment of production from fields and individual wells. These laws and regulations may limit the number of oil and natural gas wells we 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 our wells, negatively affect the economics of production from these wells or limit the number of locations we 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. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation Affecting Sales and Transportation of Commodities

Sales prices for oil, natural gas and NGLs are not currently regulated and therefore are dictated by the prevailing market prices. Although prices of these energy commodities are currently unregulated, Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and natural gas, or the prices charged for these commodities, might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures and what effect, if any, the proposals might have on our operations. Sales of oil and natural gas may be subject to certain state and federal reporting requirements.

The price and terms of service of transportation of commodities, including access to pipeline transportation capacity, are subject to extensive federal and state regulation. Such regulation may affect the marketing of oil and natural gas produced, as well as the revenues received for sales of such production. Gathering systems may be subject to state ratable take statutes and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil and natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase, or accept for gathering, without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes may affect whether and to what extent gathering capacity is available for oil and natural gas production, if any, of the drilling program and the cost of such capacity. Further, state laws and regulations govern rates and terms of access to intrastate pipeline systems, which may similarly affect market access and cost.

To the extent that the Company enters into transportation contracts with pipelines that are subject to FERC regulation, the Company is subject to FERC requirements related to use of such capacity. Any failure on the Company's part to comply with FERC's regulations and policies related to pipeline transportation, reporting requirements or other regulations, and any failure to comply with a FERC-related pipeline's tariff, could result in the imposition of civil and criminal penalties. In addition, any changes in FERC or state regulations or requirements on pipeline transportation may result in increased transportation costs on pipelines that are subject to such regulation, thereby negatively impacting the Company's profitability.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment and occupational health and safety. These laws and regulations may, among other things: (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (v) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transportation, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our purchasers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While compliance with existing environmental laws and regulations has not had a material adverse effect on our operations to date, we can provide no assurance that this will continue in the future.

The following is a summary of the more significant existing and proposed environmental, occupational health and safety laws and regulations to which our business operations are or may be subject to and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act ("RCRA"), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes.

Pursuant to rules issued by the U.S. Environmental Protection Agency (the "EPA"), individual state governments administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. A change in the classification of exploration and production wastes has the potential to significantly increase our waste disposal costs to manage, which in turn will result in increased operating costs and could adversely impact our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, 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. We generate materials in the course of our operations that may be regulated as hazardous substances. Despite the "petroleum exclusion" of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state and local laws. Under such laws, we could be required to undertake investigatory, response, or corrective measures, which could include soil and groundwater sampling, the removal of previously disposed substances and wastes, the cleanup of contaminated property, or remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including wetland areas, is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers (the "USACE") or an analogous state agency. In September 2015, the EPA and the USACE issued a final rule outlining federal jurisdictional reach under the CWA over waters of the U.S., including wetlands, which has since been subject to several revisions. In May 2023, the Supreme Court decided *Sackett v. EPA*, which significantly narrowed the scope of "waters of the United States." Under *Sackett*, the word "waters" refers only to "those relatively permanent, standing or continuously flowing bodies of water forming geographic features that are described in ordinary parlance as streams, oceans, rivers, and lakes" and to "wetlands that are as a practical matter indistinguishable from waters of the United States." In August 2023, the EPA finalized a rule amending the definition of "waters of the United States" to conform with the recent Supreme Court decision in *Sackett*. However, litigation challenging aspects of the January 2023 definition not addressed by *Sackett* is ongoing. To the extent future changes expand the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. In addition, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. We do not expect the costs to comply with the requirements of the CWA to have a material adverse effect on our operations.

The Oil Pollution Act of 1990 amends the CWA and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, this law requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasures plans.

Safe Drinking Water Act and Saltwater Disposal Wells

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled or otherwise disposed of on the lease may be sent to saltwater disposal wells for injection into subsurface formations. Underground injection operations are regulated under the federal Safe Drinking Water Act and permitting and enforcement authority may be delegated to state governments. In Texas, the Texas Railroad Commission ("RRC") regulates the disposal of produced water by injection well. The RRC requires operators to obtain a permit from the agency for the operation of saltwater disposal wells and establishes minimum standards for injection well operations. In response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related waste waters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or placed volumetric injection limits on existing wells or imposed moratoria on the use of such injection wells. In response to concerns related to induced seismicity, regulators in some states have already adopted or are considering additional requirements related to seismic safety. For example, the RRC has adopted rules for injection wells to address these seismic activity concerns in Texas. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. More stringent regulation of injection wells could lead to reduced construction or the capacity of such wells, which could in turn impact the availability of injection wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. The costs associated with the disposal of proposed water are commonly incurred by all oil and natural gas producers, however, and we do not believe that these costs will have a material adverse effect on our operations.

Air Emissions

The federal Clean Air Act 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 us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly 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, we 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 for ozone from 75 to 70 parts per billion. The EPA approved final attainment/nonattainment designations with the new ozone standards in July 2018 and currently all of the areas in which we operate are in attainment with such standards. However, state implementation of these revised air quality standards or a change in the attainment status of the areas in which we operate could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant.

Separately, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. The EPA has also adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels.

Given the long-term trend toward increasing regulation, these and future laws and air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. We do not believe that compliance with such requirements, however, will have a material adverse effect on our operations.

Regulation of Greenhouse Gas Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") endanger public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration ("PSD"), construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations. In December 2023, the EPA finalized New Source Performance Standard ("NSPS") Subpart OOOOb, which seeks to reduce methane and volatile organic compound emissions from the oil and natural gas source category and NSPS Subpart OOOOc, which create, for the first-time, emission guidelines for existing oil and natural gas sources that would be included in individual states' implementation plans. These standards expand upon previously issued NSPS Subparts OOOO and OOOOa published by the EPA in 2012 and 2016, respectively. In January 2024, the EPA issued a proposed rule implementing a methane fee required under the Inflation Reduction Act of 2022.

Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, it should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events; if any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic Fracturing Activities

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. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, resulting in new legislative and regulatory initiatives that seek to increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 that prohibit wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, 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 certain limited circumstances. Also, the federal Bureau of Land Management ("BLM") published a final rule in 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands; however, the BLM rescinded the 2015 rule in 2017.

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, or prohibit hydraulic fracturing or high volume hydraulic fracturing altogether. For example, in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Endangered Species Act and Migratory Birds

The federal 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' habitat. We 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, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service (the "FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a 2011 settlement agreement, the FWS was required to make a determination on listing of more than 250 species as endangered or threatened under the FSA by no later than completion of the agency's 2017 fiscal year. The FWS missed the deadline but reportedly continues to review new species for protected status under the ESA pursuant to the settlement agreement. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. In 2023, Recently, the FWS proposed that the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, be listed as endangered under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Administration ("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 and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us 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 on-going operations. These permits are generally subject to protest, appeal, or litigation, which, in certain cases, can delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities 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 us. The occurrence of a significant event that is not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2023, nor do we anticipate that such expenditures will be material in 2024.

Competition and Markets

The business of acquiring producing properties and non-producing leases suitable for exploration and development is highly competitive. Our competition, in our efforts to acquire both producing and non-producing properties, include oil and gas companies, independent concerns, income programs and individual producers and operators, many of which have financial resources, staffs and facilities substantially greater than those available to us. Furthermore, domestic producers of oil and gas must not only compete with each other in marketing their output, but must also compete with producers of imported oil and gas and alternative energy sources such as coal, nuclear power and hydroelectric power. Competition among petroleum companies for favorable oil and gas properties and leases can be expected to increase. The Company also faces competition from companies that supply alternative sources of energy, such as wind, solar and other renewables. Competition will increase as alternative energy technology becomes more reliable and governments throughout the world support or mandate the use of such alternative energy.

The availability of a ready market for any oil and gas produced by us at acceptable prices per unit of production will depend upon numerous factors beyond our control, including the extent of domestic production and importation of oil and gas, the proximity of our producing properties to gas pipelines and the availability and capacity of such pipelines, the marketing of other competitive fuels, fluctuation in demand, governmental regulation of production, refining, transportation and sales, general national and worldwide economic conditions, and use and allocation of oil and gas and their substitute fuels. There is no assurance that we will be able to market all of the oil or gas produced by us or that favorable prices can be obtained for the oil and gas production.

We derive our revenue and cash flow principally from the sale of oil, natural gas and NGLs. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil, natural gas and NGLs. We sell our oil and natural gas on the open market at prevailing market prices or through forward delivery contracts. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing. The market price for oil, natural gas and NGLs is dictated by supply and demand; consequently, we cannot accurately predict or control the price we may receive for our oil, natural gas and NGLs.

We have an active hedging program to mitigate risk regarding our cash flow and to protect returns from our development activity in the event of decreases in the prices received for our production; however, hedging arrangements may expose us to risk of financial loss in some circumstances and may limit the benefit we would receive from increases in the prices for oil, natural gas and NGLs.

Oil and Gas Industry Considerations

The COVID-19 pandemic resulted in a severe worldwide economic downturn, significantly disrupting the demand for oil throughout the world, and created significant volatility, uncertainty and turmoil in the oil and gas industry. Since mid-2020, while oil prices have improved with demand steadily increasing, worldwide oil inventories, from a historical perspective, remain low. In addition, concerns exist with the ability of OPEC and other oil producing nations to meet forecasted future oil demand growth, with many OPEC countries not able to produce at their OPEC agreed upon quota levels due to their limited capital investments directed towards developing incremental oil supplies over the past few years. Furthermore, sanctions, import bans and price caps on Russia have been implemented by various countries in response to the war in Ukraine, further impacting global oil supply. As a result of these and other oil and gas supply constraints, the world has experienced significant increases in energy costs. In March 2024, OPEC announced a continuation of its 2.2 MMBOPD production cut that started in July 2023 related to the uncertainty surrounding the global economy and future oil demand. As a result of the global supply and demand imbalances experienced in 2023, oil and gas prices remained strong with average NYMEX oil and NYMEX gas prices for the three months ended December 31, 2023 being \$78.41 per Bbl and \$2.84 per Mcf, respectively, as compared to \$82.79 per Bbl and \$5.76 per Mcf, respectively, for the same period in 2022. In addition, economic volatility and geopolitical tensions have resulted in global supply chain disruptions, which has led to significant cost inflation. Global oil price levels and inflationary pressures will ultimately depend on various factors that are beyond the Company's control, such as (i) the ability of OPEC and other oil producing nations to manage the global oil supply, (ii) the impact of sanctions and import bans on production from Russia, (iii) the timing and supply impact of any Iranian sanction relief on their ability to export oil, (iv) the global supply chain constraints associated with manufacturing and distribution delays, (v) oilfield service demand and cost inflation, and (vi) political stability of oil consuming countries and oil producing regions. The Company continues to assess and monitor the impact of these factors and consequences on the Company and its operations.

Major Customers

The Company sells its oil and gas production to a number of direct purchasers under direct contracts or through other operators under joint operating agreements. Listed below are the percent of the Company's total oil and gas sales made which represented more than 10% of the Company's oil and gas sales in the year 2023.

Oil Purchasers:	
APA Corporation	22%
Crivitas Resources Inc.	20%
Plains All American Inc.	19%
DE IV Operating, LLC.	14%
Gas Purchasers:	
APA Corporation	17%
Civitas Resources Inc.	10%

Although there are no long-term purchasing agreements with these purchasers, we believe that they will continue to purchase our oil and gas products and, if not, could be readily replaced by other purchasers.

Employees

At December 31, 2023, we had 115 full time employees, 25 of whom were employed at our principal offices in Houston, Texas, at the offices of Prime Operating Company, Eastern Oil Well Service Company and EOWS Midland Company, and 90 employees who were primarily involved in our district operations in Midland and Carrizo Springs, Texas, Elmore City and Oklahoma City, Oklahoma.

Item 1A. RISK FACTORS

General Risk Factors

The prices of oil, NGL and gas are highly volatile. A sustained decline in these commodity prices could materially and adversely affect the Company's business, financial condition and results of operations.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Natural gas prices, based on the twelve-month average of the first of the month Henry Hub index price, were \$2.637 per MMBTU in 2023 as compared to \$6.358 per MMBTU in 2022, and have averaged \$2.446 per MMBTU for the first three months of 2024. Oil prices, based on West Texas Intermediate(WTI) Light Sweet Crude first of the month prices, averaged \$78.22 per barrel in 2023 as compared to \$93.67 per barrel in 2022, and in the first three months of 2024, the first of the month price has averaged \$77.48 per barrel.

Any substantial or extended decline in future natural gas or crude oil prices would have a material adverse effect on our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments. Furthermore, substantial, extended decreases in natural gas and crude oil prices may cause us to delay or postpone a significant portion of our exploration, development and exploitation projects or may render such projects uneconomic, which may result in significant downward adjustments to our estimated proved reserves and could negatively impact our ability to borrow and cost of capital and our ability to access capital markets, increase our costs under our revolving credit facility, and limit our ability to execute aspects of our business plans.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of consumer product demand;
- the domestic and foreign supply of natural gas and oil
- weather conditions and natural disasters;

- political conditions in natural gas and oil producing regions, including the Middle East, Russia, Africa and South America;
- actions by the members of the Organization of Petroleum Exporting Countries with respect to oil production levels and announcements of potential changes in such levels;
- the price levels and quantities of foreign imports to the United States;
- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices;
- conservation and environmental protection efforts, including activities by non-governmental organizations to restrict the exploration, development and production of natural gas and oil;
- overall economic conditions; and
- global or national health concerns, including the outbreak of pandemic or contagious disease.

In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write down, as a noncash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

Concerns over general economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European, Asian and the United States financial markets have in the past contributed, and may in the future contribute, to economic uncertainty and diminished expectations for the global economy. In addition, ongoing conflict in Ukraine and the Middle East, the occurrence or threat of terrorist attacks in the United States or other countries and global or national health concerns could adversely affect the global economy. These factors, combined with volatility in commodity prices, business and consumer confidence and unemployment rates, may precipitate an economic slowdown. Concerns about global economic growth may have an adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition. These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas and oil prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Financial difficulties encountered by our oil and natural gas purchasers, third-party operators or other third parties could decrease cash flow from operations and adversely affect our exploration and development activities.

We derive essentially all of our revenues from the sale of our oil, natural gas and NGLs to unaffiliated third-party purchasers, independent marketing companies and midstream companies. Any delays in payments from such purchasers caused by their financial difficulties, including those resulting from continued volatility in both credit and commodity markets, will have an immediate negative effect on our results of operations and cash flows.

Additionally, liquidity and cash flow problems encountered by our working interest co-owners or the third-party operators of our non-operated properties may prevent or delay the drilling of a well or the development of a project. Our working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a working interest owner, we could be required to pay the working interest owner's share of the project costs.

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all.

We rely upon access to our revolving credit facility as a source of liquidity for any capital requirements not satisfied by cash flow from operations or other sources. Future challenges in the global financial system, including the capital markets, may adversely affect our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. Adverse economic and market conditions could adversely affect the collectability of our trade receivables and cause our commodity hedging counterparties to be unable to perform their obligations or to seek bankruptcy protection. Future challenges in the economy could also lead to reduced demand for natural gas which could have a negative impact on our revenues.

Our debt agreements also require compliance with covenants to maintain specified financial ratios. If the price that we receive for our natural gas and oil production further deteriorates from current levels or continues for an extended period, it could lead to further reduced revenues, cash flow and earnings, which in turn could lead to a default under those ratios. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period. A prolonged period of decreased natural gas and oil prices or a further decline could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. In order to provide a margin of comfort with regard to these financial covenants, we may seek to reduce our capital expenditure plan, sell non-strategic assets or opportunistically modify or increase our derivative instruments to the extent permitted under our debt agreements. In addition, we may seek to refinance or restructure all or a portion of our indebtedness. We cannot assure you that we will be able to successfully execute any of these strategies, and such strategies may be unavailable on favorable terms or not at all.

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, GHG emissions, climate change or methane 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. In addition, investors currently focused on the potential effectiveness of climate change may elect to shift some or all of their investments into non-fossil fuel energy related investments. Limitation of investments in and financings for fossil fuel energy could restrict the availability of capital, resulting in the restriction, delay, or cancellation of development and production activities.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance coverage against certain, but not all, hazards that could arise from our operations. Such insurance is believed to be reasonable for the hazards and risks faced by us. We do not carry business interruption insurance. In addition, pollution and environmental risks are not fully insurable.

We maintain for our operations total excess liability insurance with limits of \$20 million per occurrence and in the aggregate covering certain general liability and certain "sudden and accidental" environmental risks with a deductible of \$100,000 per occurrence, subject to all terms, restrictions and sub-limits of the policies. We also maintain general liability insurance limits of \$1 million per occurrence and \$2 million in the aggregate.

We have several policies that cover environmental risks. We have environmental coverage under the per occurrence and aggregate limits of our general and umbrella liability policies (for a twelve-month term). These policies provide third-party surface cleanup, bodily injury and property damage coverage, and defense costs when a pollution event is sudden and accidental and is discovered within thirty days of commencement and reported to the insurance company within ninety days of discovery. This is standard coverage in oil and gas insurance policies.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers and contractors. However, customers and contractors who provide contractual indemnification protection may not in all cases maintain adequate insurance to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may not be able to maintain adequate insurance in the future at rates we consider reasonable.

From time to time, a small number of our contractors have requested contractual provisions that require us to respond to third-party claims. In some of these instances we have accepted the risk with the understanding that it would be covered under our current coverage. We evaluate these risk-transferring negotiations cautiously, and we feel that we have adequately mitigated this risk through existing coverage or acquiring supplemental coverage when appropriate.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. If there were insufficient capacity available on these facilities, if these facilities were unavailable to the Company or if access to these facilities were to become commercially unreasonable, the price offered for the Company's production could be significantly depressed, or the Company could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons while it constructs its own facility or awaits the availability of third party facilities. The Company also relies (and expects to rely in the future) on facilities developed and owned by third parties in order to gather, store, process, transport, fractionate, refine, export and sell its oil, NGL and gas production. The Company's plans to develop and sell production from its oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient gathering, transportation, storage, processing, fractionation, refining or export facilities to the Company, especially in areas of planned expansion where such facilities do not currently exist. Our failure to obtain these services on acceptable terms could materially harm our business.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

A failure of technology systems, data breach or cyber incident could materially affect our operations .

Our information technology systems may be vulnerable to security breaches, including those involving cyberattacks using viruses, worms or other destructive software, process breakdowns, phishing or other malicious activities, or any combination of the foregoing. Such breaches could result in unauthorized access to information, including customer, employee, or other confidential data. We do not carry insurance against these risks, although we do invest in security technology, perform penetration tests, and design our business processes to attempt to mitigate the risk of such breaches. However, there can be no assurance that security breaches will not occur. Moreover, cyber and other security threats are constantly evolving, thereby making it more difficult to successfully defend against them or to implement adequate preventative measures. The development and maintenance of these measures requires continuous monitoring as technologies change and security measures evolve. We have experienced, and expect to continue to experience, cyber threats and incidents, none of which has been material to us to date. However, a successful breach or attack could have a material negative impact on our operations or business reputation and subject us to consequences such as litigation and direct costs associated with incident response.

Information technology solution failures, network disruptions, breaches of data security and cyberattacks could disrupt our operations by causing delays, impeding processing of transactions and reporting financial results, resulting in the unintentional disclosure of customer, employee or our information, or damage to our reputation. A system failure, data security breach or cyberattack could have a material adverse effect on our financial condition, results of operations or cash flows. In the past, we have experienced data security breaches resulting from unauthorized access to our e-mail systems, which to date have not had a material impact on our business; however, there is no assurance that such impacts will not be material in the future.

In addition to the risks presented to our systems and networks, cyber attacks affecting oil and natural gas distribution systems maintained by third parties, or the networks and infrastructure on which they rely, could delay or prevent delivery of our production to markets. Further, cyber attacks on a communications network or power grid could cause operational disruption resulting in loss of revenues. A cyber attack of this nature would be outside our control, but could have a material, adverse effect on our business, financial condition and results of operations.

Risks Related to our Business

The shut-in of our wells could negatively impact our production, liquidity, and, ultimately, our operations, results, and performance.

Our production depends, in part, upon our wells that are capable of commercial production not being shut-in (i.e., suspended from production). The lack of availability of capacity on third-party systems and facilities or the shut-in of an oil field's production could result in the shut-in of our wells.

The producing wells in which we have an interest occasionally experience reduced or terminated production. These curtailments can result from mechanical failures, contract terms, pipeline and processing plant interruptions, market conditions, operator priorities, and weather conditions. These curtailments can last from a few days to many months, any of which could have an adverse effect on our results of operations.

If we experience low oil production volumes due to the shut-in of our wells or other mechanical failures or interruptions, it would impact our ability to generate cash flows from operations and we could experience a reduction in our available liquidity. A decrease in our liquidity could adversely affect our ability to meet our anticipated working capital, debt service, and other liquidity needs.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

- decreases in natural gas and oil prices;
- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- loss of title or other title related issues;
- surface access restrictions;
- lack of available gathering or processing facilities or delays in the construction thereof;

- lack of available capacity on interconnecting transmission pipelines;
- lack of available drilling and production equipment or availability of oil field labor;
- compliance with, or changes in, governmental requirements and regulation, including with respect to wastewater disposal, discharge of GHGs and fracturing; and
- shortages or delays in the availability of required goods or services such as drilling rigs or crews, the delivery of equipment and the availability of sufficient water for drilling operations.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate within a particular geographic area may decline. We may be unable to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may be unable to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. As a result, estimates of different engineers may vary. In addition, the extent, quality and reliability of this technical data can vary. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board ("FASB") in Accounting Standards Codification ("ASC") Section 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

The Company's expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development and infill drilling activities. These drilling locations and prospects represent a significant part of the Company's future drilling plans. The Company's ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company's ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company's ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately meet the Company's expectations for success. As such, the Company's actual drilling activities may materially differ from the Company's current expectations, which could have a significant adverse effect on the Company's proved reserves, financial condition and results of operations.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves. In addition, there are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates and associated costs and the assumption of potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates.

We are continually identifying and evaluating opportunities to acquire natural gas and oil properties. We may not be able to successfully consummate any acquisition, to acquire producing natural gas and oil properties that contain economically recoverable reserves, or to integrate the properties into our operations profitably.

The borrowing base under our revolving credit facility may be reduced in light of recent commodity price declines, which could limit us in the future.

The borrowing base under our revolving credit facility is currently \$85 million, and lender commitments under our revolving credit facility are \$300 million. The borrowing base is redetermined semi-annually under the terms of the revolving credit facility. In addition, either we or the lenders may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for other reasons set forth in our revolving credit agreement. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets to meet our obligations, including any such debt repayment obligations.

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2024 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2024 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- uncontrolled flows of natural gas, oil or well fluids;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures. Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to the Company due to injury or loss of life, damage to or destruction of wells, production facilities, other property or natural resources, clean-up responsibilities, regulatory investigations and penalties and suspension of operations.

The nature of the Company's assets and production operations may impact the environment or cause environmental contamination, which could result in material liabilities to the Company.

The Company's assets and production operations may give rise to significant environmental costs and liabilities as a result of the Company's handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to its operations, and due to past industry operations and waste disposal practices. The Company's oil and gas business involves the generation, handling, treatment, storage, transport and disposal of wastes, hazardous substances and petroleum hydrocarbons and is subject to environmental hazards, such as oil and produced water spills, NGL and gas leaks, pipeline and vessel ruptures and unauthorized discharges of such wastes, substances and hydrocarbons, that could expose the Company to substantial liability due to pollution and other environmental damage. For example, drilling fluids, produced waters and certain other wastes associated with the Company's exploration, development and production of oil or gas are currently excluded under RCRA from the definition of hazardous waste. These wastes are instead regulated under RCRA's less stringent non-hazardous waste provisions. There have been efforts from time to time to remove this exclusion. For example, in response to a federal consent decree issued in 2016, the EPA was required during 2019 to determine whether certain Subtitle D criteria regulations required revision in a manner that could result in oil and gas wastes being regulated as RCRA hazardous waste. In April 2019, the EPA made a determination that such revision of the regulations was unnecessary. Any future loss of the RCRA exclusion could have a material adverse effect on the Company's results of operations and financial position.

The Company currently owns, leases or operates, and in the past has owned, leased or operated, properties that for many years have been used for oil and gas exploration and production activities, and petroleum hydrocarbons, hazardous substances and wastes may have been released on or under such properties, or on or under other locations, including off-site locations, where such substances have been taken for treatment or disposal. These wastes, substances and hydrocarbons may also be released during future operations. In addition, some of the Company's properties have been operated by predecessors or previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under the Company's control. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons, hazardous substances and wastes on, under or from the Company's properties. Private parties, including lessors of properties on which the Company operates and the owners or operators of properties adjacent to the Company's operations and facilities where the Company's petroleum hydrocarbons, hazardous substances or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as seek damages for noncompliance with environmental laws and regulations or for personal injury or damage to property or natural resources. Such properties and the substances disposed or released on or under them may be subject to CERCLA, RCRA and analogous state laws, which could require the Company to remove previously disposed substances, wastes and petroleum hydrocarbons, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination, the costs of which could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company may not be able to recover some or any of these costs from sources of contractual indemnity or insurance, as pollution and similar environmental risks generally are not insurable or fully insurable, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. These hedging arrangements limit the benefit to us of increases in prices. While there are many different types of derivatives available, we generally utilize put options and swap agreements to attempt to manage price risk more effectively.

The put options used to establish floor prices for a fixed volume of production during a certain time period. They provide for payments from the counterparties if the index price falls below the floor. The swap agreements call for payments to, or receipts from, counterparties based on whether the index price for the period is greater or less than the fixed price established for that period when the swap is put in place. These arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

The CFTC has promulgated regulations to implement statutory requirements for swap transactions. These regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. While we believe that our use of swap transactions exempt us from certain regulatory requirements, the changes to the swap market due to increased regulation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Legal and Regulatory Risks

Laws and regulations regarding hydraulic fracturing, as well as governmental reviews of such activities, could result in increased costs and additional operating restrictions, delays or cancellations and have a material adverse effect on the Company's production.

Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons from tight formations. The Company conducts hydraulic fracturing in its drilling and completion programs. The process involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to stimulate oil and gas production. The process is typically regulated by state oil and gas commissions or similar agencies, but in recent years, several federal agencies have conducted investigations or asserted regulatory authority over certain aspects of the process. For example, in 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. Additionally, the EPA has asserted regulatory authority pursuant to the SDWA's UIC program over hydraulic fracturing activities involving the use of diesel and has issued guidance covering such activities. Moreover, the EPA has published an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing under the Toxic Substances Control Act and has implemented a final rule under the CWA prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly-owned wastewater treatment plants. Also, the BLM published a final rule in 2015 that established new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. The BLM rescinded the 2015 rule in late 2017; however, new or more stringent regulations may be promulgated in the future.

From time to time, the U.S. Congress has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the additives used in the hydraulic-fracturing process. In addition, certain states, including Texas where the Company operates, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, disposal and well-construction requirements on hydraulic-fracturing operations. For example, in April 2019, Colorado passed legislation reforming exploration and production activities by the oil and gas industry in the state including, among other things, revising the mission of the state oil and gas agency from fostering energy development in the state to instead focusing on regulating the industry in a manner that is protective of public health and safety and the environment, as well as authorizing cities and counties to regulate oil and gas operations within their jurisdictions as they do other development. While the Company does not conduct operations in Colorado, passage or enactment of similar legislation in other states in which it does operate could significantly increase the Company's operating costs and have a significant adverse effect on the Company's ability to conduct operations. States could elect to prohibit hydraulic fracturing or high volume hydraulic fracturing altogether, following the approach taken by the states of Vermont, Maryland, Washington and New York. Also, local land use restrictions, such as city ordinances, may be adopted to restrict or prohibit drilling in general or hydraulic fracturing in particular. In Texas, legislation was adopted providing that the regulation of oil and gas operations in Texas is under the exclusive jurisdiction of the state and thus preempts local regulation of those operations. Nonetheless, municipalities and political subdivisions in Texas continue to have the right to enact "commercially reasonable" regulations for surface activities.

In the event federal, state or local restrictions or bans pertaining to hydraulic fracturing are adopted in areas where the Company is currently conducting operations, or in the future plans to conduct operations, the Company may incur additional costs to comply with such requirements, experience restrictions, delays or cancellations in the pursuit of exploration, development or production activities, and perhaps be limited or precluded in the drilling of wells or in the volume that the Company is ultimately able to produce from its reserves; one or more of which developments could have a material adverse effect on the Company.

The Company's operations are subject to stringent environmental, oil and gas-related and occupational safety and health laws and regulations that could cause it to delay, curtail or cease its operations or expose it to material costs and liabilities.

The Company's operations are subject to stringent federal, state and local laws and regulations governing, among other things, the drilling of wells, rates of production, the size and shape of drilling and spacing units or proration units, the transportation and sale of oil, NGL and gas, and the discharging of materials into the environment and environmental protection. For example, state laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and gas properties. Some states allow forced pooling or integration of tracts to facilitate development, while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company's interest in the unitized properties. In addition, state conservation laws (i) establish maximum rates of production from oil and gas wells, (ii) generally prohibit the venting or flaring of gas and (iii) impose requirements regarding production rates. These laws and regulations may limit the amount of oil and gas the Company can produce from the Company's wells or limit the number of wells or the locations that the Company can drill.

In connection with its operations, the Company must obtain and maintain numerous environmental and oil and gas-related permits, approvals and certificates from various federal, state and local governmental authorities, and may incur substantial costs in doing so. The need to obtain permits has the potential to delay, curtail or cease the development of oil and gas projects. The Company may in the future be charged royalties on gas emissions or required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone from 75 parts per billion to 70 parts per billion under standards to provide protection of public health and welfare. In subsequent years, the EPA has issued area designations with respect to ground-level ozone and final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of the Company's equipment, resulting in longer permitting timelines, and significantly increase the Company's capital expenditures and operating costs. In another example, the EPA and U.S. Army Corps of Engineers (the "Corps") released a final rule in 2015 outlining federal jurisdictional reach under the CWA over waters of the U.S., including wetlands, which has since been subject to several revisions. In August 2023, the EPA finalized a rule amending the definition of "waters of the United States" to conform with the recent Supreme Court decision in *Sackett v. EPA*. However, litigation challenging aspects of the January 2023 definition not addressed by *Sackett* is ongoing. To the extent that future changes to the definition expand the scope of the CWA's jurisdiction in areas where the Company conducts operations, the Company could incur (i) delays, restrictions or prohibitions in the issuance of necessary permits, (ii) restrictions or cessations in the development or expansion of projects, or (iii) increases in the Company's capital expenditures and operating expenses by, for example, requiring installation of new emission controls on some of the Company's equipment, any one or more of which developments could have a material adverse effect on the Company's business, financial condition and results of operations.

Additionally, the Company's operations are subject to a number of federal and state laws and regulations, including the federal OSHA and comparable state statutes, whose purpose is to protect the health and safety of employees. Among other things, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in the Company's operations and that this information be provided to employees, state and local government authorities and citizens.

There can be no assurance that existing or future regulations will not result in a delay, curtailment or cessation of production or processing activities, result in a material increase in the costs of production, development, exploration or processing operations or materially and adversely affect the Company's future operations and financial condition. Noncompliance with these laws and regulations may subject the Company to sanctions, including administrative, civil or criminal penalties, remedial cleanups or corrective actions, delays in permitting or performance of projects, natural resource damages and other liabilities. Such laws and regulations may also affect the costs of acquisitions. In addition, these laws and regulations are subject to amendment or replacement in the future with more stringent legal requirements. Further, any delay, reduction or curtailment of the Company's development and producing operations due to these laws and regulations could result in the loss of acreage through lease expiration.

The Company's operations are subject to a number of risks arising out of concerns regarding the threat of climate change, including regulatory, political, litigation and financial risks, that could result in increased operating costs and costs of compliance, limit the areas in which oil and gas production may occur, reduce demand for the oil and gas the Company produces, and expose the Company to the risk of increased activism and decreased funding for the industry, while the potential physical effects of climate change could disrupt the Company's production and cause it to incur significant costs in preparing for or responding to those effects.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. Numerous initiatives have been proposed and are expected to continue to be proposed at the international, national, regional and state levels of government to monitor and limit existing sources of GHG emissions as well as to restrict or eliminate emissions from new sources. As a result, the Company's operations are subject to a series of regulatory, political, litigation and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the CAA, the EPA has adopted regulations that, among other things, (i) establish construction and operating permit reviews for GHG emissions from certain large stationary sources, (ii) require the monitoring and annual reporting of GHG emissions from certain petroleum and gas system sources in the United States, (iii) implement CAA emission standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and gas sector, and (iv) together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. For example, in December 2023, the EPA finalized NSPS Subpart OOOOb, which seeks to reduce methane and volatile organic compound emissions from the oil and natural gas source category and NSPS Subpart OOOOc, which create, for the first-time, emission guidelines for existing oil and natural gas sources that would be included in individual states' implementation plans. These standards expand upon previously issued NSPS Subparts OOOO and OOOOa published by the EPA in 2012 and 2016, respectively. Additionally, various states, groups of states, and other countries have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there is a non-binding agreement, the United Nations sponsored "Paris Agreement," for nations to limit their GHG emissions through individually-determined reduction goals every five years after 2020. The United States withdrew from the Paris Agreement in November 2020 but reentered the agreement in February 2021. In April 2021, the Biden administration announced a new goal to reduce GHG emissions by 50% to 52% economy-wide by 2030 compared to 2005 levels. In August 2022, President Biden signed into law the Inflation Reduction Act, which created a methane emissions reduction program, provided significant funding to reduce emissions of methane from the oil and gas sector, and requires the EPA to impose a charge on certain oil and gas sources.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States. President Biden and the Democratic Party have identified climate change as a priority, and it is possible that additional executive orders and/or regulatory action targeting GHG emissions, or prohibiting or restricting oil and gas development activities in certain areas, will be proposed and/or promulgated during the Biden Administration. Litigation risks are also increasing, as a number of cities, local governments or other persons have sought to bring suit against oil and gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also financial risks for fossil fuel producers as stockholders or bondholders currently invested in fossil-fuel energy companies concerned about the threat of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, investing and lending practices of various investment firms and institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the Paris Agreement, and foreign citizenry concerned about the threat of climate change not to provide funding for fossil fuel producers. For example, there have been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds, to divest of fossil fuel equities and lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

The adoption and implementation of new or more stringent international, federal or state regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and gas sector or otherwise restrict the areas in which this sector may produce oil and gas or generate GHG emissions could result in increased compliance and consumption costs, and thereby reduce demand for the oil and gas the Company produces. Additionally, political, litigation and financial risks could result in the restriction or cancellation of production activities, incurring liability for infrastructure damages as a result of climate change, or impairing the Company's ability to continue to operate in an economic manner. Finally, if increasing concentrations of GHGs in the Earth's atmosphere were to result in significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events, then such effects could have a material adverse effect on the Company's exploration and production operations.

In addition, companies in the oil and gas industry have been the target of activist efforts from both individuals and non-governmental organizations, including instituting litigation and supporting political or regulatory efforts to, among other things, limit or ban hydraulic fracturing, restrict or ban certain operating practices, including the disposal of waste materials, such as hydraulic fracturing fluids and produced water, deny or delay drilling permits, prohibit the venting or flaring of gas, reduce access of the oil and gas industry to federal and state government lands, and delay or cancel oil and gas developmental or expansion projects. The Company may need to incur significant costs associated with responding to these initiatives, and complying with any resulting additional legal or regulatory requirements could have a material adverse effect on the Company's business, financial condition, cash flows and results of operations.

Laws and regulations pertaining to protection of threatened and endangered species or to critical habitat, wetlands and natural resources could delay, restrict or prohibit the Company's operations and cause it to incur substantial costs that may have a material adverse effect on the Company's development and production of reserves.

The federal ESA and comparable state laws were established to protect endangered and threatened species. Under the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Federal Migratory Bird Treaty Act. Oil and gas operations in the Company's operating areas may be adversely affected by seasonal or permanent restrictions imposed on drilling activities by the U.S. Fish and Wildlife Services (the "FWS") that are designed to protect various wildlife, which may materially restrict the Company's access to federal or private land use. Permanent restrictions imposed to protect endangered and threatened species could prohibit drilling in certain areas, impact suppliers of critical materials or services, or require the implementation of expensive mitigation measures. Additionally, federal statutes, including the CWA, the OPA and CERCLA, as well as comparable state laws, prohibit certain actions that adversely affect critical habitat, wetlands and natural resources. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling, construction or releases of petroleum hydrocarbons, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties.

Moreover, as a result of one or more settlements entered into by the FWS, the agency is required to make determinations on the potential listing of numerous species as endangered or threatened under the ESA. The designation of previously unprotected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or could result in delays, restrictions or prohibitions on its development and production activities that could have a material adverse effect on the Company's ability to develop and produce reserves.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations.

It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Increasing scrutiny and changing expectations from investors, lenders and other market participants with respect to our Environmental, Social and Governance ("ESG") policies may impose additional costs on us or expose us to additional risks.

Companies across all industries are facing increasing scrutiny relating to their ESG policies. Investor advocacy groups, certain institutional investors, investment funds, lenders and other market participants are increasingly focused on ESG practices and in recent years have placed increasing importance on the implications and social cost of their investments. The increased focus and activism related to ESG and similar matters may hinder access to capital, as investors and lenders may decide to reallocate capital or not to commit capital as a result of their assessment of a company's ESG practices. Companies that do not adapt to or comply with investor, lender or other industry shareholder expectations and standards, which are evolving, or which are perceived to have not responded appropriately to the growing concern for ESG issues, regardless of whether there is a legal requirement to do so, may suffer from reputational damage and the business, financial condition or stock price of such a company could be materially and adversely affected.

We may face increasing pressures from investors, lenders and other market participants, who are increasingly focused on climate change, to prioritize sustainable energy practices, reduce our carbon footprint and promote sustainability. As a result, we may be required to implement more stringent ESG procedures or standards so that our existing and future investors and lenders remain invested in us and make further investments in us. If we do not meet these standards, our business or our ability to access capital could be harmed.

Additionally, certain investors and lenders have and may continue to exclude companies engaged in exploration and production activity, such as us, from their investing portfolios altogether due to ESG factors. These limitations in both the debt and equity capital markets may affect our ability to grow as our plans for growth may include accessing those markets. If those markets are unavailable, or if we are unable to access alternative means of financing on acceptable terms, or at all, we may be unable to implement our business strategy, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness. At the same time, some stakeholders and regulators have increasingly expressed or pursued opposing views, legislation, and investment expectations with respect to ESG, including the enactment or proposal of "anti-ESG" legislation or policies.

Further, it is likely that we will incur additional costs and require additional resources to monitor, report and comply with wide ranging ESG requirements, including the SEC climate change disclosure rules. Similarly, these policies may negatively impact the ability of our customers to access debt and capital markets. The occurrence of any of the foregoing could have a material adverse effect on our business and financial condition.

Changes to the U.S. federal tax laws could adversely affect our financial position, results of operations and cash flow.

Our future effective tax rates could be adversely affected by changes in tax laws, both domestically and internationally, or the interpretation or application thereof. From time to time, U.S. and foreign tax authorities, including state and local governments consider legislation that could increase our effective tax rate.

The IRA includes a 1% tax on publicly traded corporations on the fair market value of stock repurchased during any taxable year. Such tax applies to the extent such buybacks exceed \$1 million during such year, which buyback value may be offset by other stock issuances.

Further, the U.S. Congress has advanced a variety of tax legislation proposals, and while the final form of any legislation is uncertain, the current proposals, if enacted, could have a material effect on our effective tax rate. Additionally, in recent years, lawmakers and the U.S. Department of the Treasury have proposed certain significant changes to U.S. tax laws applicable to oil and gas companies. These changes include, but are not limited to; (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, and (iii) an extension of the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. This legislation or any future similar changes in U.S. federal income tax laws, as well as any similar changes in state law, could eliminate or postpone certain tax deductions that currently are available with respect to natural gas and oil exploration and production, which could negatively affect our results of operations and financial condition.

Item 1B. UNRESOLVED STAFF COMMENTS.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 1C. CYBERSECURITY

As an oil and gas producer, the Company is dependent on digital technology in many areas of its business and operations. Additionally, the Company gathers and safeguards sensitive information as a part of its regular business activities. The Company continually evaluates and integrates new processes, systems and resources to enhance its defenses against cybersecurity threats.

Governance

The Board is responsible for overseeing the Company's enterprise risk management processes and has delegated oversight of cybersecurity and other information technology risks to the Executive Committee, a standing committee of the Board. The Executive Committee oversees management's implementation and execution of the Company's Cybersecurity Program and IRP. The Executive Committee receives in-depth annual reports from the Director of Information Technology (DIT) or Assistant Director of Information Technology (ADIT) detailing relevant cybersecurity risks to the Company and, as necessary, timely periodic updates based on circumstances, regarding any significant cybersecurity incidents or developments. The Executive Committee reports to the Board regarding its activities, including those related to cybersecurity.

At the management level, the Company's cybersecurity governance includes a Cybersecurity Steering Committee which is comprised of a subset of the Company's Executive Committee and other key officers, leaders, and subject matter experts from various disciplines across the Company. The Cybersecurity Steering Committee meets quarterly to receive updates from the DIT and/or ADIT on Company-related cyber risks, monitor compliance with the Company's Cyber Security Program, and to review cybersecurity policies.

The Company's cybersecurity risk management and strategy processes are managed by the DIT and the ADIT who have 40 and 20 years of work experience, respectively, in various roles involving systems security, operations and compliance. These individuals are informed about and monitor the prevention, detection, mitigation and remediation of cybersecurity incidents through their management of internal information technology personnel and retained third-party personnel involved in the cybersecurity risk management and strategy processes described above, including the operation of the IRP.

Cybersecurity Program Management

The Company has developed and implemented an information security program (the Cybersecurity Program), which includes various processes and controls intended to protect the confidentiality, integrity and availability of the Company's systems and information. We have also implemented an incident response plan (the IRP) that applies in the event of a cybersecurity threat or incident to provide a standardized framework for responding to security incidents. The IRP sets out a coordinated approach to investigating, containing, documenting and mitigating incidents, including reporting findings and keeping senior management and other key stakeholders informed and involved as appropriate.

The Company's Cybersecurity Program and incident response processes were primarily designed and assessed to align with the cybersecurity framework published by the National Institute of Standards and Technology. In addition to our internal cybersecurity capabilities, the Company retains or engages various third-parties in connection with design, implementation and monitoring of certain cybersecurity-related processes and controls.

Key aspects of the Company's Cybersecurity Program include:

- Risk assessments designed to help identify material cybersecurity risks to critical systems and the company-wide information technology environment;
- Continuous monitoring of Company systems and conducting periodic penetration tests;
- An IRP that includes procedures for responding to cybersecurity incidents;
- Required cybersecurity trainings for employees, incident response personnel, and management related to physical security of assets, data privacy and other information security policies and procedures; and
- A third-party risk management process for its service providers, suppliers, vendors and other business associates.

The Cybersecurity Program is integrated into the Company's overall enterprise risk management process and shares common methodologies, reporting channels, and governance processes that apply across the enterprise risk management process to other legal, compliance, strategic, operational, and financial risk areas. Cyber risks identified in the overall enterprise risk management process are reviewed annually by the Executive Committee.

Risks from Cybersecurity Threat

As of the date of this Annual Report on Form 10-K, the Company has not identified any cybersecurity incidents, including any prior cybersecurity incidents, that have materially affected the Company's operations, business strategy, results of operations and cash flows. The Company faces various ongoing risks from cybersecurity threats that, if realized, are reasonably likely to lead to losses of sensitive information, critical infrastructure or capabilities essential to the Company's operations and could have a material adverse effect on the Company's reputation, financial position, results of operations and cash flows. See "Item 1A. Risk Factors - The Company's business could be materially and adversely affected by security threats, including cybersecurity threats, and other disruptions" for additional information.

Item 2. PROPERTIES.

Our executive offices, as well as offices of Prime Operating Company, Eastern Oil Well Service Company and EOWS Midland Company are located in leased premises in Houston, Texas.

We maintain district offices in Midland, Texas and Oklahoma City, Oklahoma and have field offices in Carrizo Springs and Midland, Texas, as well as, Elmore City, Oklahoma.

Substantially all of our oil and gas properties are subject to a mortgage given to collateralize indebtedness or are subject to being mortgaged upon request by our lenders for additional collateral.

The information set forth below concerning our properties, activities, and oil and gas reserves includes our interests in affiliated entities.

The following table sets forth the exploratory and development drilling experience with respect to wells in which we participated during the three years ended December 31, 2023.

	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil	—	—	—	—	—	—
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development:						
Oil	35	8.37	8	0.76	13	4.73
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total:						
Oil	35	8.37	8	0.76	13	4.73
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
	<u>35</u>	<u>8.37</u>	<u>8</u>	<u>0.76</u>	<u>13</u>	<u>4.73</u>

Oil and Gas Production

As of December 31, 2023, we had ownership interest in the following number of gross and net producing oil and gas wells (1).

	Gross	Net
Producing Oil Wells(1)	898	400
Producing Gas Wells(1)	220	33

(1) A gross well is a well in which a working interest is owned. A net well is the sum of the fractional working interests owned in gross wells.

The following table shows our net production of oil, NGL and natural gas for each of the three years ended December 31, 2023. "Net" production is net after royalty interests of others are deducted and is determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold, mineral or royalty interest owned by us.

	2023	2022	2021
Oil (barrels)	1,144,000	939,000	738,000
NGL (barrels)	606,000	417,000	416,000
Gas (Mcf)	4,127,000	3,325,000	3,236,000

The following table sets forth our average sales prices together with our average production costs per unit of production for the three years ended December 31, 2023.

	2023	2022	2021
Average sales price per barrel of oil	\$ 76.84	\$ 96.70	\$ 68.39
Average sales price per barrel of NGL	\$ 19.64	\$ 35.70	\$ 26.97
Average sales price per Mcf of natural gas	\$ 1.93	\$ 5.54	\$ 3.53
Average production costs per net equivalent barrel of oil (1)	\$ 12.98	\$ 16.07	\$ 13.76

(1) Net equivalent barrels are computed at a rate of 6 Mcf per barrel and costs exclude production taxes.

Average oil, NGL and gas prices received including the impact of derivatives were:

	2023	2022	2021
Average sales price per barrel of oil	\$ 76.33	\$ 87.77	\$ 64.04
Average sales price per barrel of NGL	\$ 19.64	\$ 35.70	\$ 26.97
Average sales price per Mcf of natural gas	\$ 1.93	\$ 4.44	\$ 2.97

Acreage

The following table sets forth the approximate gross and net undeveloped acreage in which we have leasehold and mineral interests as of December 31, 2023. "Undeveloped acreage" is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Leasehold acreage	84,668	24,725	—	—	84,668	24,725
Mineral fee acreage	1,640	117	19,257	417	20,897	534
Total	86,308	24,842	19,257	417	105,565	25,259

Total Net Undeveloped Acreage Expiration

In the event that production is not established, or we take no action to extend or renew the terms of our leases, our net undeveloped acreage that will expire over the next three years, as of December 31, 2023, is zero acres for the year ending December 31, 2024, zero in 2025, and zero acres in 2026.

Reserves

All of our interests in proved developed and undeveloped oil and gas properties have been evaluated by Ryder Scott Company, L.P. for each of the three years ended December 31, 2023. The professional qualifications of the technical persons primarily responsible for overseeing the preparation of the reserve estimates can be found in Exhibit 99.1, the Ryder Scott Company, L.P. Report on Registrant's Reserves Estimates. In matters related to the preparation of our reserve estimates, our district managers report to the Engineering Data manager, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual preparation of reserve estimates of 100% of our year-end reserves by our independent third-party engineers, Ryder Scott Company, L.P. The members of our districts consist of degreed engineers and geologists with over twenty-five years of industry experience and between ten and twenty-five years of experience managing our reserves. Our Engineering Data manager, the technical person primarily responsible for overseeing the preparation of reserves estimates, has over thirty years of experience, holds a Bachelor degree in Geology and an MBA in finance and is a member of the Society of Petroleum Engineers and American Association of Petroleum Geologist. See Part II, Item 8 "Financial Statements and Supplementary Data", for additional discussions regarding proved reserves and their related cash flows. All of our reserves are located within the continental United States. The following table summarizes our oil and gas reserves at each of the respective dates:

As of December 31,	Reserve Category								Total			
	Proved Developed				Proved Undeveloped							
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)
2021	5,386	2,882	23,902	12,252	—	—	—	—	5,386	2,882	23,902	12,252
2022	4,143	2,497	22,277	10,353	3,028	1,833	9,030	6,366	7,171	4,330	31,307	16,719
2023	5,757	3,676	24,749	13,558	6,254	5,156	24,470	15,488	12,011	8,832	49,219	29,046

- (a) In computing total reserves on a barrels of oil equivalent (Boe) basis, gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil and NGLs are converted based upon volume; one barrel of natural gas liquids equals one barrel of oil.

During 2021, in West Texas, we participated with Apache in the drilling of three additional horizontals on the Kashmir Tract in Upton County, Texas and completed these three wells in September of 2021 along with six other wells drilled in 2020 on the same lease that were drilled but uncompleted at year-end. The Company has an average of 47.8% interest in these nine wells and invested approximately \$30 million in these horizontal wells. Also in 2021, the Company participated with Oviniv Mid-Continent for 11.25% interest in four two-mile horizontal wells in Canadian County, Oklahoma. Twelve of these thirteen horizontal wells were successfully completed and placed into production in the fourth quarter of 2021. One of the Oviniv wells had a casing leak issue and has been temporarily abandoned. The Company invested approximately \$32 million in these thirteen wells. In addition, in 2021, the Company added minor reserves through over-riding royalty interest in two wells drilling and completed in Grady County, Oklahoma.

At December 31, 2021, the Company had 159 Mboe of proved developed shut-in reserves attributable to three horizontals drilled and completed in Canadian County, Oklahoma, but not yet online at year-end. These reserves were converted to proved producing in the first quarter of 2022. At year-end 2021, we did not include proved undeveloped reserves in our reserve report because we had not yet received definitive drilling proposals from third-party operators for the more than fifteen horizontal wells that we planned to participate in located primarily in West Texas.

In 2022, the Company participated in eight horizontal wells that were drilled and completed; four located in Irion County, West Texas, operated by SEM Operating Company, in which we have 10.13% interest, and four located in Canadian County, Oklahoma, operated by Oviniv Mid-Continent, Inc., in which we have an average 9% interest. Our investment in these eight wells was approximately \$4 million and all were brought on production in August of 2022. In addition, the Company added reserves through 15 wells in which we have various minor over-riding royalty interest. Eight of these wells are located in West Texas and seven are located in Oklahoma.

In the fourth quarter of 2022, we began participation in the drilling of 20 horizontal wells located in West Texas operated by three different operators. In Martin County, we participated with ConocoPhillips in five 2.5-mile-long horizontal wells in which the Company has 20.83% interest and had capital investment of \$12.1 million. In Reagan County, we participated with Hibernia Energy III (now Civitas Resources) in 10 two-mile horizontals with 25% interest and an investment of approximately \$25.6 million. Also in Reagan County, we participated with Double Eagle (DE IV) in five two-mile-long horizontals with nearly 50% interest, carrying a net capital outlay of \$23.4 million. All twenty of these West Texas wells were completed and online in the second quarter of 2023.

At year-end 2022, the Company had 6,366 Mboe of proved undeveloped reserves attributable to the 25 horizontal wells described above.

In 2023, the Company participated with five operators in the drilling and completion of 35 horizontal wells: 32 of these are located in West Texas and three are located in Oklahoma. In total, including the cost of facilities, the Company invested approximately \$91 million, 99% of which is attributable to the wells in West Texas where we have been drilling horizontal wells targeting various proven pay intervals in the Wolfcamp and Spraberry formations. At December 31, 2023, we had 12 wells completed but not producing that were all brought into production in January of 2024. These 12 wells account for 1,278 MBOE of proved developed reserves at year-end. In addition, as of December 31, 2023, the Company was in the process of drilling and completing 34 wells in West Texas, 28 of which are considered proved undeveloped, and six of which are considered probable undeveloped. The year-end reserve report includes only proved reserves, therefore expected reserves from the six probable undeveloped wells are not included in the reserve report.

At year-end 2023, the Company had 15,489 MBOE of proved undeveloped reserves that are attributable to 52 undeveloped wells, 28 of which were in the process of being drilled or completed at year-end.

The estimated future net revenue (using current prices and costs as of those dates) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for our proved developed and proved undeveloped oil and gas reserves at the end of each of the three years ended December 31, 2023, are summarized as follows (in thousands of dollars):

As of December 31,	Proved Developed		Proved Undeveloped		Total			
	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow
2021	\$ 275,227	\$ 171,906	\$ —	\$ —	\$ 275,227	\$ 171,906	\$ 36,100	\$ 135,806
2022	\$ 320,146	\$ 192,688	\$ 200,790	\$ 118,081	\$ 520,936	\$ 310,769	\$ 66,233	\$ 244,536
2023	\$ 314,415	\$ 213,281	\$ 253,959	\$ 138,679	\$ 568,374	\$ 351,960	\$ 73,912	\$ 278,048

The PV10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although this measure is not in accordance with U.S. generally accepted accounting principles ("GAAP"), we believe that the presentation of the PV10 Value is relevant and useful to investors because it presents the discounted future net cash flow attributable to proved reserves prior to taking into account corporate future income taxes and the current tax structure. We use this measure when assessing the potential return on investment related to oil and gas properties. The PV10 of future income taxes represents the sole reconciling item between this non-GAAP PV10 Value versus the GAAP measure presented in the standardized measure of discounted cash flow. A reconciliation of these values is presented in the last three columns of the table above. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to proved oil and natural gas reserves after income tax, discounted at 10%.

"Proved developed" oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. "Proved undeveloped" oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

In accordance with U.S. generally accepted accounting principles, product prices are determined using the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, adjusted for oilfield or gas gathering hub and wellhead price differentials (e.g. grade, transportation, gravity, sulfur, and basic sediment and water) as appropriate. Also, in accordance with SEC specifications and U.S. generally accepted accounting principles, changes in market prices subsequent to December 31 are not considered.

While it may be reasonably anticipated that the prices received for the sale of our production may be higher or lower than the prices used in this evaluation, as described above, and the operating costs relating to such production may also increase or decrease from existing levels, such possible changes in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation for the SEC case. Actual volumes produced, prices received and costs incurred may vary significantly from the SEC case.

Natural gas prices, based on the twelve-month average of the first of the month Henry Hub index price, were \$2.64 per MMBtu in 2023 as compared to \$6.36 per MMBtu in 2022 and \$3.60 per MMBtu in 2021. Oil prices, based on the West Texas Intermediate (WTI) Light Sweet Crude first of the month average spot price, were \$78.22 per barrel in 2023 as compared to \$93.67 per barrel in 2022, and \$66.56 per barrel in 2021. Since January 1, 2023, we have not filed any estimates of our oil and gas reserves with, nor were any such estimates included in any reports to, any federal authority or agency, other than the Securities and Exchange Commission.

District Information

The following table represents certain reserves and well information as of December 31, 2023.

	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves as of December 31, 2023 (MBoe)					
Developed	563	2,210	10,778	7	13,558
Undeveloped	—	—	15,488	—	15,488
Total	563	2,210	26,266	7	29,046
Average Net Daily Production (Boe per day)	173	831	6,172	4	7,181
Gross Productive Wells (Working Interest and ORRI Wells)	114	511	647	222	1,494
Gross Productive Wells (Working Interest Only)	72	361	541	144	1,118
Net Productive Wells (Working Interest Only)	21	132	275	5	433
Gross Operated Productive Wells	28	128	334	—	490
Gross Operated Water Disposal, Injection and Supply wells	5	39	8	—	52

In several of our producing regions we have field service groups to service our operated wells and locations as well as third-party operators in the area. These services consist of well service support, site preparation and construction services for drilling and workover operations. Our operations are performed utilizing workover or swab rigs, water transport trucks, saltwater disposal facilities, various land excavating equipment and trucks we own and that are operated by our field employees.

Gulf Coast Region

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in southeast Texas. This region is managed from our office in Houston, Texas. Principal producing intervals are in the Wilcox, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 114 producing wells (21 net) in the Gulf Coast region as of December 31, 2023, of which 28 wells are operated by us. Average net daily production in our Gulf Coast Region at year-end 2023 was 173 Boe. At December 31, 2023, we had 563 MBoe of proved reserves in the Gulf Coast region, which represented 2% of our total proved reserves. We maintain an acreage position of over 7,468 gross (4,699 net) acres in this region, primarily in Colorado, Newton, and Polk counties. We operate a field service group in this region from a field office in Carrizo Springs, Texas utilizing two workover rigs, twenty water transport trucks, two hot-oil trucks, a cement truck, and two saltwater disposal wells to provide oil field services for third-party operators in South Texas. As of March 31, 2024, the Gulf Coast region has no operated wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. This region is managed from our office in Oklahoma City, Oklahoma. As of December 31, 2023, we had 511 producing wells (132 net) in the Mid-Continent area, of which 128 wells are operated by us. Principal producing intervals are in the Robberson, Avant, Skinner, Sycamore, Bromide, McLish, Hunton, Mississippian, Oswego, Red Fork, and Chester formations at depths ranging from 1,100 to 10,500 feet. Average net daily production in our Mid-Continent Region in 2023 was 831 Boe. At December 31, 2023, we had 2,210 MBoe of proved reserves in the Mid-Continent area, representing 8% of our total proved reserves. We maintain an acreage position of approximately 46,960 gross (10,137 net) acres in this region, primarily in Canadian, Kingfisher, Grant, Major, and Garvin counties. Our Mid-Continent region is actively participating with third-party operators in the horizontal development of lands that include Company owned interest in several counties in the Stack and Scoop plays of Oklahoma where drilling is primarily targeting reservoirs of the Mississippian, and Woodford formations.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. The oil and gas in this basin are produced primarily from five intervals; the Upper and Lower Spraberry, the Wolfcamp, the Strawn, and the Atoka, at depths ranging from 6,700 feet to 11,300 feet. This region is managed from our office in Midland, Texas. As of December 31, 2023, we had 647 wells (275 net) in the West Texas area, of which 334 wells are operated by us. Principal producing intervals are in the Spraberry, Wolfcamp, and San Andres formations at depths ranging from 4,200 to 12,500 feet. Average net daily production in Our West Texas Region at year-end 2023 was 6,172 Boe. At December 31, 2023, we had 26,267 MBoe of proved reserves in the West Texas area, or 90% of our total proved reserves. We maintain an acreage position of approximately 16,407 gross (9,341 net) acres in the Permian Basin in West Texas, primarily in Reagan, Upton, Martin and Midland counties and believe this acreage has significant resource potential for horizontal drilling in the Spraberry, Jo Mill, and Wolfcamp intervals. We operate a field service group in this region utilizing nine workover rigs, three hot oiler trucks, and one kill truck. Oil field support is provided for drilling and workover operations both to third-party operators as well as for our own operated wells and locations.

As of March 31, 2024, the Company was participating in the drilling or completion of 34 horizontal wells in Reagan County, Texas with an average of 39% interest in 14 wells, 8.3% in 12 wells, 50% in six wells and less than 1% in two wells. Combined, we expect to spend approximately \$80 million in these horizontals and their associated facilities. Twenty-eight of these 34 wells and their forecast reserves are included in the 2023 year-end reserve report as proved undeveloped, whereas the reserves of six wells are considered probable undeveloped and not included in the reserve report. Additionally, we have 12 horizontals slated to begin drilling in the second quarter of 2024 and be on production in the third quarter.

In 2024, we expect to complete 54 new horizontal wells, investing approximately \$140 million. We are also preparing to invest approximately \$95 million in another 23 horizontal wells to be drilled and completed in 2025. In addition, we have identified 28 horizontal locations for future development in West Texas that we anticipate to be drilled in the 2026-2027 timeframe and would require a net investment of approximately \$67 million.

Item 3. LEGAL PROCEEDINGS.

In the ordinary course of conducting our business, we become involved in litigation and other claims from private party actions, as well as judicial and administrative proceedings involving governmental authorities at the federal, state, and local levels. While the outcome of litigation or other proceedings against us cannot be predicted with certainty, management does not expect that any loss resulting from such litigation or other proceedings, in excess of any amounts accrued or covered by insurance, will have a material adverse impact on our consolidated financial statements.

Item 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II—OTHER INFORMATION

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock is listed and principally traded on the Nasdaq Stock Market under the ticker symbol "PNRG".

As of April 4, 2024 there were 200 registered holders of the common stock.

We have not paid any dividends during the three most recent fiscal years or any subsequent interim period, and we do not intend to pay any cash dividends in the foreseeable future. Provisions of our line of credit agreement restrict our ability to pay dividends. Such dividends may be declared out of funds legally available therefore, when and as declared by our Board of Directors.

Issuer Sales and Purchases of Equity Securities

There were no sales of equity securities by the Company during the period covered by this report. The following table details the Company's purchases of shares for the three months ended December 31, 2023.

2023 Month	Total Number of Shares Purchased	Average Price Paid per share	Maximum Number of Shares That May Yet Be Purchased Under The Program at Month-End (1)
October	7,000	\$ 110.43	275,044
November	1,000	\$ 107.39	274,044
December	400	\$ 109.35	273,644
Total/Average	8,400	\$ 100.02	

(1) In December 1993, we announced that the Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of the common stock from time-to-time, in open market transactions or negotiated sales. On October 31, 2012, June 13, 2018 and June 7, 2023, the Board of Directors of the Company approved an additional 500,000, 200,000 and 300,000 shares respectively, of the Company's stock to be included in the stock repurchase program. A total of 4,000,000 shares have been authorized to date under this program. Through December 31, 2023, a total of 3,726,356 shares have been repurchased under this program for \$89,987,612 at an average price of \$24.15 per share. The stock repurchase program has no specific term. Additional purchases of shares may occur as market conditions warrant. We expect future purchases will be funded with internally generated cash flow or from working capital.

PART II—OTHER INFORMATION

Item 6. RESERVED

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Report contains additional information that should be referred to when reviewing this material. Our subsidiaries are listed in Note 1 to the Consolidated Financial Statements.

Overview:

We are an independent oil and natural gas company engaged in acquiring, developing, and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, and Oklahoma. In addition, we own a substantial amount of well servicing equipment. All of our oil and gas properties and interests are located in the United States. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities. Our primary sources of liquidity are cash generated from our operations and our credit facility.

We attempt to assume the position of operator in all acquisitions of producing properties and will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests. We continue to actively pursue the acquisition of producing properties. To diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets to build stockholder value through consistent growth in our oil and gas reserve base on a cost-efficient basis.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of any increases in oil and gas prices above the maximum fixed amount specified in the derivative agreements and subjects us to the credit risk of the counterparties to such agreements. Since all our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in gains and losses on mark-to-market derivative contracts in our consolidated statement of operations as changes occur in the NYMEX price indices.

Market Conditions and Commodity Prices:

Our financial results depend on many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. In addition, our realized prices are further impacted by our derivative and hedging activities. We derive our revenue and cash flow principally from the sale of oil, natural gas and NGLs. As a result, our revenues are determined, to a large degree, by prevailing prices for crude oil, natural gas and NGLs. We sell our oil and natural gas on the open market at prevailing market prices or through forward delivery contracts. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing. The market price for oil, natural gas and NGLs is dictated by supply and demand; consequently, we cannot accurately predict or control the price we may receive for our oil, natural gas and NGLs. Index prices for oil, natural gas, and NGLs have improved since the lows of 2020 however we expect prices to remain volatile and consequently cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital program, production volumes or revenues.

Critical Accounting Estimates:

Proved Oil and Gas Reserves

Proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids 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 estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. 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. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively. Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Asset Retirement Obligation (ARO):

The Company has significant obligations to remove tangible equipment and restore land at the end of oil and gas production operations. The Company's removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety, and public relations considerations. ARO associated with retiring tangible long-lived assets is recognized as a liability in the period in which the legal obligation is incurred and becomes determinable. The liability is offset by a corresponding increase in the underlying asset. The ARO liability reflects the estimated present value of the amount of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit-adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value.

Liquidity and Capital Resources:

Our primary sources of liquidity are cash generated from our operations, through our producing oil and gas properties, field services business and sales of acreage, and available capacity under our revolving credit facility.

Net cash provided by operating activities for the year ended December 31, 2023 was \$109.0 million compared to \$33.1 million in the prior year. Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control.

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility, we sometimes lock in prices for some portion of our production through the use of derivatives.

If our exploratory drilling results in significant new discoveries, we will have to expend additional capital to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the successful wells and our record of reserve growth in recent years, we will be able to access sufficient additional capital through bank financing.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2024, we will continue our focus on preserving financial flexibility and liquidity as we manage the risks facing our industry. Our 2024 capital budget is reflective of commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity, we may adjust our capital program throughout the year, divest assets, or enter into strategic joint ventures.

The Company maintains a Credit Agreement with a maturity date of June 1, 2026, providing for a credit facility totaling \$300 million, with a borrowing base of \$85 million. As of March 31, 2024, the Company had \$4 million in outstanding borrowings and \$81 million in availability under this facility. The bank reviews the borrowing base semi-annually and, at its discretion, may decrease or propose an increase to the borrowing base relative to a re-determined estimate of proved oil and gas reserves. The next borrowing base review is scheduled for May 2024. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial and operational covenants defined in the agreement. We are currently in compliance with these covenants and expect to be in compliance over the next twelve months. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for other reasons set forth in our revolving credit agreement. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the re-determined borrowing base.

Our credit agreement requires us to hedge a portion of our production as forecasted for the PDP reserves included in our borrowing base review engineering reports. The credit agreement requires that as of the last day of any fiscal quarter, if the borrowing base utilization percentage on such a date is less than the 15%, then the borrower shall not be required to enter into any swap agreements. As of the quarter ended December 31, 2023, the Company had no outstanding borrowings. Accordingly, the Company had no swap agreements in place for oil and natural gas.

The Company's activities include development and exploratory drilling. Our strategy is to develop a balanced portfolio of drilling prospects that includes lower risk wells with a high probability of success and higher risk wells with greater economic potential. Horizontal development of our resource base provides superior returns relative to vertical development due to the ability of each horizontal wellbore to come in contact with a greater volume of reservoir rock across a greater distance, more efficiently draining the reserves with less infrastructure and thus at a lower cost per acre.

In 2023, including 20 wells spud in the fourth quarter of 2023, the Company participated with five operators in 35 wells: 32 of these are located in West Texas and three are located in Oklahoma. The Company invested approximately \$91 million in these wells, including in their production facilities, almost all attributable to wells drilled and completed in West Texas where we are focused on horizontal development of various proven pay intervals in the Wolfcamp and Spraberry formations. On December 31, 2023, we had 12 wells completed that were all brought into production in January of 2024. In addition to \$7.9 million of the \$91 million invested in these wells in 2023, the Company had an additional \$15.5 million investment in these 12 wells. Also at year-end 2023, the Company was in the process of drilling and completing 34 wells in West Texas that carry an expense of \$80.6 million, and planning for a 50% participation in an additional 12 wells to be drilled in 2024 that will require an investment of approximately \$43 million. In total, the Company expects to invest \$140 million in 54 wells in 2024 and, in 2025, to invest \$95 million in an additional 23 wells in West Texas.

During 2023, to supplement cash flow and finance our future drilling programs, the Company sold 368 net mineral acres as well as 7.8 surface acres in Midland County, Texas receiving gross proceeds of \$436,050 and recognizing a gain of \$47,000.

In the second quarter of 2023, the Company acquired 55 net acres in the South Stiles area of Reagan County, Texas for \$605,000, and in a separate agreement also in Reagan County, the Company sold 320 non-core acres for proceeds of \$6,000,000. In addition, the Company sold 36.51% interest in one well in Midland County, Texas for proceeds of \$60,000.

In the third quarter of 2023, the Company sold a non-core 38.25-acre leasehold tract in Martin County, Texas for proceeds of \$899,000 and sold 3 surface acres in Liberty County, Texas for net proceeds of \$37,053. Also in the third quarter, in various counties of Oklahoma, the Company divested its interest in 39 wells, reducing its future plugging liability by approximately \$1.5 million. Effective July 1, 2023, the Company acquired the operations of 36 wells from DE Permian and 50% of DE Permian's original ownership in such wells. In addition, in Reagan County, Texas, the Company acquired 114.52 net acres from DE Permian for \$1,700,853 and assigned to them 203.23 net acres.

In the fourth quarter of 2023, the Company sold 136 surface acres in Oklahoma for net proceeds of \$306,000 and in Midland Texas sold 9.35 net acres for proceeds of \$280,423.

Proceeds from these sales in 2023, along with our cash flow, were used to eliminate the Company's outstanding bank debt as of March 31, 2023. As noted above, as of March 31, 2024, the Company had \$4 million outstanding borrowings and \$81 million in availability under this facility.

The majority of our capital spending is discretionary, and the ultimate level of expenditures will be dependent on our assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

The Company has a stock repurchase program in place, spending under this program in 2023 and 2022 was \$7.5 million and \$7.4 million, respectively. The Company expects continued spending under the stock repurchase program in 2024.

Results of Operations

2023 and 2022 Compared

We reported a net income of \$28.1 million for 2023, or \$15.19 per share, compared to \$48.7 million, or \$24.91 per share for 2022. The current year net income reflects production increases offset by commodity price decreases. The significant components of income and expense are discussed below.

Oil, NGL and gas sales decreased \$16.4 million, or 13.19% to \$107.7 million for the year ended December 31, 2023 from \$124.1 million for the year ended December 31, 2022. Crude oil, NGL and natural gas sales vary due to changes in volumes of production sold and realized commodity prices. Our realized prices at the well head decreased an average of \$19.86 per barrel, or 20.54% on crude oil, decreased an average of \$16.06 per barrel, or 44.99% on NGL and decreased \$3.62 per Mcf, or 65.34% on natural gas during 2023 as compared to 2022.

Our crude oil production increased by 205,000 barrels, or 21.83% to 1,144,000 barrels for the year ended December 31, 2023 from 939,000 barrels for the year ended December 31, 2022. Our NGL production increased by 189,000 or 45.32% to 606,000 for the year ended December 31, 2023 from 417,000 barrels for the year ended December 31, 2022. Our natural gas production increased by 802 MMcf, or 24.12% to 4,127 MMcf for the year ended December 31, 2023 from 3,325 MMcf for the year ended December 31, 2022. The changes in crude oil, NGL and natural gas production volumes are a result of new wells placed in production offset by the natural decline of existing properties.

The following table summarizes the primary components of production volumes and average sales prices realized for the years ended December 31, 2023 and 2022 (excluding realized gains and losses from derivatives).

	Years ended December 31,		Increase / (Decrease)	Increase / (Decrease)
	2023	2022		
Barrels of Oil Produced	1,144,000	939,000	205,000	21.83%
Average Price Received	\$ 76.84	\$ 96.70	\$ (19.86)	(20.54)%
Oil Revenue (In 000's)	\$ 87,906	\$ 90,803	\$ (2,897)	(3.19)%
Mcf of Gas Sold	4,127,000	3,325,000	802,000	24.12%
Average Price Received	\$ 1.92	\$ 5.54	\$ (3.62)	(65.34)%
Gas Revenue (In 000's)	\$ 7,935	\$ 18,428	\$ (10,493)	(56.94)%
Barrels of Natural Gas Liquids Sold	606,000	417,000	189,000	45.32%
Average Price Received	\$ 19.64	\$ 35.70	\$ (16.06)	(44.99)%
Natural Gas Liquids Revenue (In 000's)	\$ 11,901	\$ 14,887	\$ (2,986)	(20.06)%
Total Oil & Gas Revenue (In 000's)	\$ 107,742	\$ 124,118	\$ (16,376)	(13.19)%

Oil, Natural Gas and NGL Derivatives We do not apply hedge accounting to any of our commodity based derivatives, thus changes in the fair market value of commodity contracts held at the end of a reported period, referred to as mark-to-market adjustments, are recognized as unrealized gains and losses in the accompanying condensed consolidated statements of operations. As oil and natural gas prices remain volatile, mark-to-market accounting treatment creates volatility in our revenues.

The following table summarizes the results of our derivative instruments for the years ended December 2023 and 2022:

	Years ended December 31,	
	2023	2022
Oil derivatives - realized gains (losses)	\$ 179	\$ (12,101)
Oil derivatives – unrealized gains	--	3,713
Total gains (losses) on oil derivatives	\$ 179	\$ (8,388)
Natural gas derivatives – realized gains (losses)	235	(4,543)
Natural gas derivatives – unrealized gains	--	892
Total gains (losses) on natural gas derivatives	\$ 235	\$ (3,651)
Total gains (losses) on oil and natural gas	\$ 414	\$ (12,039)

Prices received for the years ended December 31, 2023 and 2022, respectively, including the impact of derivatives were:

	2023	2022	Increase / (Decrease)	Increase / (Decrease)
Oil Price	\$ 76.33	\$ 87.77	\$ (11.44)	(13.03)%
Gas Price	\$ 1.93	\$ 4.44	\$ (2.51)	(56.53)%
NGL Price	\$ 19.64	\$ 35.70	\$ (16.06)	(44.99)%

Oil and gas production expense increased \$1.0 million, or 4.0% to 3.11% for the year ended December 31, 2023 from \$31.7 million for the year ended December 31, 2022. These changes reflect the cost savings related to wells that have been plugged offset by rising service costs and additional costs related to the new wells that have been placed on production.

Field service income increased \$2.4 million or 18.5% to \$15.4 million for the year ended December 31, 2023 from \$13.0 million for the year ended December 31, 2022. Workover rig services, hot oil treatments, saltwater hauling and disposal represent the bulk of our field service operations. These changes reflect the variance in equipment utilization and service rates during these periods.

Field service expense increased \$0.6 million, or 5.4% to \$11.7 million for the year ended December 31, 2023 from \$11.1 million for the year ended December 31, 2022. Field service expenses primarily consist of wages and vehicle operating expenses. The changes reflect the variance in equipment utilization during the periods represented.

Depreciation, depletion, and amortization increased \$3.6 million, or 13.1% to \$31 million for the year ended December 31, 2023 from \$27.4 million for the year ended December 31, 2022. The DD&A expense is primarily attributable to our properties in West Texas and Oklahoma, reflecting the addition of new properties offset by the declining cost basis of existing properties.

General and administrative expense decreased \$4.6 million, or 22.7% to \$15.6 million for the year ended December 31, 2023 from \$20.2 million for the year ended December 31, 2021. These changes are primarily related to employee compensation and benefits.

Gain on sale and exchange of assets of \$8.9 million for the year ended December 31, 2023 consists of sales of net mineral and surface acres in various locations in Texas and Oklahoma. The \$31.8 million for the year ended December 31, 2022 consists principally of sales of deep rights in undeveloped acreage in West Texas.

Interest expense decreased \$0.4 million, or 41.0% to \$0.5 million for the year ended December 31, 2023 from \$0.9 million for the year ended December 31, 2022. This decrease reflects the increase in rates combined with reduced borrowings under our revolving credit agreement.

Tax expense of \$6.1 million and \$10.3 million were recorded for the years ended December 31, 2023 and 2022, respectively. The change in our income tax provision was primarily due to the decrease in pre-tax income for the year ended December 31, 2023.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and supplementary information included in this Report are described in the Index to Consolidated Financial Statements at Page F-1 of this Report.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

Item 9A. CONTROLS AND PROCEDURES.

As of the end of the period covered by this Annual Report on Form 10-K, our principal executive officer and principal financial officer have evaluated the effectiveness of our "disclosure controls and procedures" ("Disclosure Controls"). Disclosure Controls, as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), are procedures that are designed with the objective of ensuring that information required to be disclosed in our reports filed under the Exchange Act, such as this Annual Report, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Disclosure Controls are also designed with the objective of ensuring that such information is accumulated and communicated to our management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Our management, including the chief executive officer and chief financial officer, does not expect that our Disclosure Controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Members of our management, including our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures, as defined by paragraph (e) of Exchange Act Rules 13a-15 or 15d-15, as of December 31, 2023 the end of the period covered by this Report. Based upon that evaluation, these officers concluded that our disclosure controls and procedures were effective as of December 31, 2023.

Management's 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. Our internal control over financial reporting is a process designed to provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition, transactions are executed in accordance with appropriate management authorization and accounting records are reliable for the preparation of financial statements in accordance with U.S. generally accepted accounting principles.

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.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2023. Management based this assessment on criteria for effective internal control over financial reporting described in "Internal Control – Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

As a result of this assessment, management concluded that, as of December 31, 2023, our internal control over financial reporting was effective in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. This Annual Report does not include an attestation report of the Company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

There have been no changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

Not applicable.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company's Directors, nominees for Directors and executive officers will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 5, 2024, and which is incorporated herein by reference.

Code of Conduct and Ethics

We have adopted a Code of Business Ethics and Conduct (the "Code") that applies to all officers and employees. The Code is publicly available under the governance tab of our website at www.primeenergy.com. Any amendments to, or waivers of, the Code with respect to our principal executive officer, principal financial officer or principal accounting officer or controller, or persons performing similar functions, will be disclosed on our website within four business days following the date of the amendment or waiver. Copies of the Code may also be requested in print by writing to PrimeEnergy Resources Corporation, 9821 Katy Freeway, Suite 1050, Houston, TX 77024.

Item 11. EXECUTIVE COMPENSATION.

Information relating to executive compensation will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 5, 2024, and which is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

Information relating to security ownership of certain beneficial owners and management will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 5, 2024, and which is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Information relating to certain transactions by Directors and executive officers of the Company will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 5, 2024, and which is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information relating to principal accountant fees and services will be included in the Company's definitive proxy statement relating to the Company's Annual Meeting of Stockholders to be held in June 5, 2024, and which is incorporated herein by reference.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this Report:

1. Financial statements (Index to Consolidated Financial Statements at page F-1 of this Report)
2. Financial Statement Schedules - All Financial Statement Schedules have been omitted because the required information is included in the Consolidated Financial Statements or the notes thereto, or because it is not required.
3. Exhibits:
 - 3.1 [Certificate of Incorporation of PrimeEnergy Resources Corporation, as amended and restated of December 21, 2018, \(filed as Exhibit 3.1 of PrimeEnergy Resources Corporation Form 8-K on December 27, 2018, and incorporated herein by reference\).](#)
 - 3.2 [Bylaws of PrimeEnergy Resources Corporation as amended and restated as of April 24, 2020 \(filed as Exhibit 3.2 of PrimeEnergy Resources Corporation Form 8-K on April 27, 2020 and incorporated herein by reference\).](#)
 - 4.1 [PrimeEnergy Resources Corporation Description of Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934, filed herewith.](#)
 - 10.18 [Composite copy of Non-Statutory Option Agreements \(Incorporated by reference to Exhibit 10.18 of PrimeEnergy Resources Corporation Form 10-K for the year ended December 31, 2004\).](#)
 - 10.22.6 [FOURTH AMENDED AND RESTATED CREDIT AGREEMENT dated as of July 5, 2022, is among PRIMEENERGY RESOURCES CORPORATION, a Delaware corporation \(the "Borrower"\), each of the Lenders from time to time party hereto and CITIBANK, N.A. \(in its individual capacity, "Citibank"\), as administrative agent for the Lenders \(in such capacity, together with its successors in such capacity, the "Administrative Agent"\) \(filed as exhibit 10.22.6 of PrimeEnergy Resources Corporation Form 10-Q for the Quarter Ended June 30 2022, and incorporated by reference\).](#)
 - 10.22.6.1 [FIRST AMENDMENT TO FOURTH AMENDED AND RESTATED CREDIT AGREEMENT, dated as of October 31, 2022 \(the "First Amendment Effective Date"\), is among PRIMEENERGY RESOURCES CORPORATION, a Delaware corporation \(the "Borrower"\), CITIBANK, N.A., as administrative agent \(in such capacity, the "Administrative Agent"\) and as Issuing Bank, each Guarantor party hereto and the financial institutions party hereto as Lenders and incorporated by reference.](#)
 - 10.22.6.2 [Second Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 9, 2024, among PrimeEnergy Resources Corporation, Citibank, N.A., as administrative agent, the guarantors and the lenders party thereto \(filed as exhibit 10.22.6.2\) of PrimeEnergy Resources Corporation Form 8-K on February 13, 2024, and incorporated by reference.](#)
 - 21 [Subsidiaries \(filed herewith\).](#)
 - 23 [Consent of Ryder Scott Company, L.P. \(filed herewith\).](#)
 - 31.1 [Certification of Chief Executive Officer pursuant to Rule 13\(a\)-14\(a\)/15d-14\(a\) of the Securities Exchange Act of 1934, as amended \(filed herewith\).](#)
 - 31.2 [Certification of Chief Financial Officer pursuant to Rule 13\(a\)-14\(a\)/15d-14\(a\) of the Securities Exchange Act of 1934, as amended \(filed herewith\).](#)
 - 32.1 [Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 \(filed herewith\).](#)
 - 32.2 [Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 \(filed herewith\).](#)
 - 97.1 [PrimeEnergy Resources Corporation Compensation Recoupment \(CLAWBACK\) Policy, \(filed herewith\).](#)
 - 99.1 [Summary Reserve Report dated March 7, 2023, of Ryder Scott Company, L.P. \(filed herewith\).](#)
 - 101.INS Inline XBRL (eXtensible Business Reporting Language) Instance Document (filed herewith)
 - 101.SCH Inline XBRL Taxonomy Extension Schema Document (filed herewith)
 - 101.CAL Inline XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith)
 - 101.DEF Inline XBRL Taxonomy Extension Definition Linkbase Document (filed herewith)
 - 101.LAB Inline XBRL Taxonomy Extension Label Linkbase Document (filed herewith)
 - 101.PRE Inline XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith)
 - 104 Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

Item 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 15th day of April, 2024.

PrimeEnergy Resources Corporation

By: /s/ Charles E. Drimal, Jr.

Charles E. Drimal, Jr.

Chairman, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated and on the 8th, day of April, 2024.

/s/ Charles E. Drimal, Jr. Chairman, Chief Executive Officer and President;
Charles E. Drimal, Jr. The Principal Executive Officer

/s/ Beverly A. Cummings Director, Executive Vice President and Treasurer;
Beverly A. Cummings The Principal Financial Officer

/s/ Clint Hurt Director
Clint Hurt

/s/ Thomas S. T. Gimbel Director
Thomas S. T. Gimbel

/s/ H. Gifford Fong Director
H. Gifford Fong

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors and Stockholders of
PrimeEnergy Resources Corporation and Subsidiaries

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PrimeEnergy Resources Corporation and Subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of income, equity and cash flows for each of the years then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the 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 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.

Depreciation, Depletion and Amortization of Oil and Gas Properties

Critical Audit Matter Description

At December 31, 2023, the carrying value of the Company's oil and gas properties was \$252.9 million, and depreciation, depletion and amortization ("DD&A") expense was \$31.0 million for the year then ended. As described in Note 1, under the successful efforts method of accounting, capitalized costs of proved properties are depleted using the units of production method based on proved reserves, as estimated by independent petroleum engineers. Proved reserve estimates are impacted by various inputs, including historical production, oil and gas price assumptions, and future operating and capital cost assumptions, among other factors. Because of the complexity involved in estimating oil and gas reserves, the Company utilized independent petroleum engineers for the year ended December 31, 2023.

Auditing the Company's DD&A calculations is complex because of the use of independent petroleum engineers and the evaluation of management's determination of the inputs described above used by the engineers in estimating oil and gas reserves.

How the Critical Audit Matter was Addressed in the Audit

Our audit procedures related to the evaluation of DD&A of oil and gas properties included the following, among others:

- We obtained an understanding and evaluated the design of the Company's controls over its process to calculate DD&A, including management's controls over the completeness and accuracy of the financial data utilized by the engineers in estimating oil and gas reserves.
- We evaluated the professional qualifications and objectivity of the Company's independent petroleum engineers responsible for the preparation of the proved oil and gas reserve estimates for select properties.
- We evaluated the methodologies and assumptions utilized by the Company's independent engineers to ensure they were reasonable and in accordance with industry standards.
- We compared the Company's recent production with its reserve estimates for properties that have significant production or significant reserve quantities and inquired of disproportionate ratios that did not align with our expectations.
- We tested the mathematical accuracy of the DD&A calculations, including comparing the oil and gas reserve amounts used in the calculations to the Company's reserve reports.

Accounting for Asset Retirement Obligations

Critical Audit Matter Description

At December 31, 2023, the asset retirement obligation ("ARO") balance totaled \$15.2 million. As further described in Note 1, the Company's ARO primarily represents the estimated present value of the amount the Company will incur to plug, abandon, and remediate producing properties at the end of their productive lives, in accordance with applicable state laws. The Company's liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and a risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions and the relatively long life of most of the Company's wells, the costs to ultimately retire the wells may vary significantly from previous estimates.

Auditing the Company's ARO is complex and highly judgmental because of the significant estimation by management in determining the obligation. In particular, the estimate was sensitive to significant subjective assumptions such as retirement cost estimates and the estimated timing of settlements, which are both affected by expectations about future market and economic conditions.

How the Critical Audit Matter was Addressed in the Audit

Our audit procedures related to the evaluation of the accounting for the ARO included the following, among others:

- We obtained an understanding and evaluated the design of the Company's internal controls over its ARO estimation process, including management's review of the significant assumptions that have a material effect on the determination of the obligations. Based on our evaluation, we designed our audit procedures to include, among others, assessing the significant assumptions and inputs used in the valuation, such as retirement cost estimates and timing of settlement assumptions.
- We compared the ARO against historical results, reviewed the reasonableness of the discount rate utilized in the estimate, considered the reasonableness of the current and long-term portion of the obligation by comparing the accretion expense trends, and considered the completeness of the properties included in the estimate by comparing to the Company's reserve reports.

/s/ GRASSI & CO., CPAs, P.C.

We have served as the Company's auditor since 1989.

Jericho, New York
April 15, 2024

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Thousands of dollars, except share data)

	As of December 31,	
	2023	2022
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 11,061	\$ 26,543
Accounts receivable, net	20,301	12,147
Prepaid obligations	376	32,839
Due from related parties	--	388
Derivative asset short-term	--	210
Other current assets	38	38
Total Current Assets	31,776	72,165
Property and Equipment		
Oil and gas properties at cost	659,792	555,280
Less: Accumulated depletion and depreciation	(406,913)	(385,811)
	252,879	169,469
Field and office equipment at cost	26,955	27,246
Less: Accumulated depreciation	(23,715)	(22,728)
	3,240	4,518
Total Property and Equipment, Net	256,119	173,987
Other assets	673	985
Total Assets	\$ 288,568	\$ 247,137
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	\$ 15,424	\$ 11,451
Accrued liabilities	48,613	25,750
Due to related parties	80	--
Current portion of asset retirement and other long-term obligations	692	2,566
Derivative liability short-term	--	1,190
	64,809	40,957
Long-Term Bank Debt	--	11,000
Asset Retirement Obligations	14,707	13,525
Deferred Income Taxes	47,236	39,968
Other Long-Term Obligations	866	1,334
Total Liabilities	127,618	106,784
Commitments and Contingencies		
Equity		
Common stock, \$.10 par value; 2023 and 2022: Authorized: 2,810,000 shares, outstanding 2023: 1,820,100 shares; outstanding 2022: 1,901,000 shares.	281	281
Paid-in capital	7,555	7,555
Retained earnings	205,669	177,566
Treasury stock, at cost; 2023: 989,900 shares; 2022: 909,000	(52,555)	(45,049)
Total Stockholders' Equity	160,950	140,353
Total Liabilities and Equity	\$ 288,568	\$ 247,137

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(Thousands of dollars, except per share amounts)

	For the Years Ended December 31,	
	2023	2022
Revenues and other income:		
Oil	\$ 87,906	\$ 90,803
Natural gas	7,935	18,428
Natural gas liquids	11,901	14,887
Field service	15,383	12,978
Interest and other income, net	417	267
Gain (loss) on derivative instruments, net	414	(12,039)
Gain on disposition of assets, net	8,854	31,789
	<u>132,810</u>	<u>157,113</u>
Costs and expenses:		
Oil and gas production	31,892	30,702
Production and advalorem taxes	7,112	7,114
Field service	11,744	11,094
Depreciation, depletion and amortization	30,976	27,401
Accretion of discount on asset retirement obligations	684	667
General and administrative	15,645	20,233
Interest	535	909
	<u>98,588</u>	<u>98,120</u>
Income before income taxes	34,222	58,993
Income tax provision	6,119	10,329
Net income attributable to common stockholders	<u>\$ 28,103</u>	<u>\$ 48,664</u>
Net Income per share attributable to Common Stockholders:		
Basic	\$ 15.19	\$ 24.91
Diluted	\$ 10.77	\$ 17.95
Weighted average shares Outstanding:		
Basic	1,849,780	1,953,916
Diluted	2,608,786	2,711,170

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(Thousands of dollars, except share amounts)

	Common Stock		Additional Paid-In Capital	Retained Earnings	Treasury Stock	Total Equity
	Shares Outstanding	Common Stock				
Balance at December 31, 2021	1,992,077	\$ 281	\$ 7,555	\$ 128,902	\$ (37,647)	\$ 99,091
Purchase of treasury stock	(91,077)	—	—	—	(7,402)	(7,402)
Net income	—	—	—	48,664	—	48,664
Balance at December 31, 2022	1,901,000	\$ 281	\$ 7,555	\$ 177,566	\$ (45,049)	\$ 140,353
Purchase of treasury stock	(80,900)	—	—	—	(7,506)	(7,506)
Net income	—	—	—	28,103	—	28,103
Balance at December 31, 2023	1,820,100	\$ 281	\$ 7,555	\$ 205,669	\$ (52,555)	\$ 160,950

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of dollars)

	For the Years Ended December 31,	
	2023	2022
Cash Flows from Operating Activities:		
Net Income	\$ 28,103	\$ 48,664
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	30,976	27,401
Accretion of discount on asset retirement obligations	684	667
Gain on sale and exchange of assets	(8,854)	(31,789)
Unrealized gain on derivative instruments	--	(4,605)
Non cash realized gain on derivative instruments, net	(980)	--
Provision for deferred income taxes	7,268	1,225
Changes in assets and liabilities:		
Accounts receivable	(8,492)	2,096
Allowance for doubtful accounts	338	(35)
Due from related parties	388	(388)
Due to related parties	80	(52)
Prepaid obligations	32,463	(32,106)
Other current assets	--	2
Accounts payable	3,973	4,169
Accrued liabilities	22,863	17,929
Other assets	673	100
Other long-term liabilities	(468)	(151)
Net Cash Provided by Operating Activities	109,015	33,127
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(113,779)	(15,974)
Proceeds from sale of properties and equipment	8,082	31,445
Net Cash (Used in) Provided by Investing Activities	(105,697)	15,471
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(7,506)	(7,402)
Increase in long-term bank debt and other long-term obligations	--	11,000
Repayment of long-term bank debt and other long-term obligations	(11,294)	(36,000)
Net Cash Used in Financing Activities	(18,800)	(32,402)
Net (Decrease) Increase in Cash and Cash Equivalents	(15,482)	16,196
Cash and Cash Equivalents at the Beginning of the Year	26,543	10,347
Cash and Cash Equivalents at the End of the Year	\$ 11,061	\$ 26,543
Supplemental Disclosures:		
Income taxes paid during the year	\$ 9,009	\$ 539
Interest paid during the year	\$ 569	\$ 842

The accompanying Notes are an integral part of these Consolidated Financial Statements

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Resources Corporation ("PERC"), a Delaware corporation, was organized in March 1973 and is engaged in the development, acquisition and production of oil and natural gas properties. PrimeEnergy Resources Corporation and its subsidiaries are herein referred to as the "Company." The Company owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the United States, primarily in Oklahoma, and Texas. The Company operates approximately 534 active wells and owns non-operating interests and royalties in approximately 952 additional wells. Additionally, the Company provides well-servicing support operations, site-preparation and construction services for oil and gas drilling and reworking operations, both in connection with the Company's activities and providing contract services for third parties. The Company is publicly traded on the Nasdaq stock market under the symbol "PNRG." PERC owns Eastern Oil Well Service Company ("EOWSC") and EOWS Midland Company ("EMID") which perform oil and gas field servicing. PERC also owns Prime Operating Company ("POC"), which serves as operator for producing oil and gas properties owned by the Company. The markets for the Company's products are highly competitive, as oil and gas are commodity products and prices depend upon numerous factors beyond the control of the Company, such as economic, political and regulatory developments and competition from alternative energy sources.

Consolidation and Presentation

The consolidated financial statements include the accounts of PrimeEnergy Resources Corporation, and its subsidiaries. All significant intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

Subsequent Events:

Subsequent events have been evaluated through the date that the consolidated financial statements were issued. During this period, there were no material subsequent items requiring disclosure, other than as stated in Footnote 4 and Footnote 5, to these consolidated financial statements.

Use of Estimates:

The preparation of consolidated financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, U.S. generally accepted accounting principles require that if the expected future undiscounted cash flows from an asset are less than its carrying cost, that asset must be written down to its fair market value. As the fair market value of an oil and gas property will usually be significantly less than the total undiscounted future net revenues expected from that asset, slight changes in the estimates used to determine future net revenues from an asset could lead to the necessity of recording a significant impairment of that asset.

Cash and cash equivalents:

The Company's cash and cash equivalents include cash on hand and short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less when purchased.

Accounts receivable, net:

The Company's net accounts receivable balance is primarily comprised of oil and gas sales receivables, joint interest receivables and other receivables for which the Company does not require collateral security. The Company's share of oil and gas production is sold to various purchasers and under various joint operating agreements. The Company records allowances for doubtful accounts based on historical collection experience, current and future economic and market conditions, the length of time that the accounts receivables have been outstanding and the financial condition of its purchasers. The Company's credit risk related to collecting accounts receivables is mitigated by using credit and other financial criteria to evaluate the credit standing of the entity obligated to make payment on the accounts receivable, and where appropriate, the Company obtains assurances of payment, such as a guarantee by the parent company of the counterparty, letters of credit or other credit support.

The Company considers forward-looking information to estimate expected credit losses. The Company establishes allowances for bad debts equal to the estimable portions of accounts receivable for which failure to collect is expected to occur. The Company estimates uncollectible amounts for joint interest receivables based on the length of time that the accounts receivables have been outstanding, historical collection experience and current and future economic and market conditions. Allowances for doubtful accounts are recorded as reductions to the carrying values of the receivables included in the Company's consolidated balance sheets and are recorded in expense in the consolidated statements of operations in the accounting periods during which failure to collect an estimable portion is determined to be probable. The Company's allowance for doubtful accounts totaled \$674 thousand and \$336 thousand as of December 31, 2023 and 2022, respectively.

In June 2016, the FASB issued ASU 2016-13, Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments. The standard's main goal is to improve financial reporting by requiring earlier recognition of credit losses on financing receivables and other financial assets in scope. This guidance is effective for Smaller Reporting Companies for fiscal years beginning after December 15, 2022, including interim periods within those fiscal periods. The Company adopted this standard effective January 1, 2023. The adoption and implementation of this ASU did not have a material impact on the Company's financial statements.

Oil and gas properties:

The Company utilizes the successful efforts method of accounting for its oil and gas properties. Under this method, all costs associated with productive wells and nonproductive development wells are capitalized while nonproductive exploration costs and geological and geophysical expenditures are expensed. Oil and gas leasehold acquisition costs are capitalized when incurred and included as unproved oil and gas properties in the consolidated balance sheets. The Company does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless both of the following conditions are met: (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The Company's exploratory wells include extension wells that extend the limits of a known reservoir. Due to the capital intensive nature and the geographical location of certain projects, it may take an extended period of time to evaluate the future potential of an exploration project and the economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production data in the area, transportation or processing facilities, and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory/extension well costs is continuous until a decision can be made that the project has found sufficient proved reserves to sanction the project or is determined to be noncommercial and is charged to exploration and abandonments expense. As of December 31, 2023, the Company had no such suspended well costs.

The capitalized costs of proved properties are depleted using the unit-of-production method based on proved reserves. Costs of significant nonproducing properties, wells in the process of being drilled and in-process development projects are excluded from depletion until the related project is completed and proved reserves are established or, if unsuccessful, abandonments expense is recognized. Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion, depreciation and amortization, if doing so does not materially impact the depletion rate of its amortization base. Generally, no gain or loss is recorded until an entire amortization base is sold. However, gain or loss is recorded from the sale of less than an entire amortization base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the amortization base.

Field and Office Equipment:

Field and office equipment is carried at cost. Depreciation of all other equipment is determined under the straight-line method using various rates based on useful lives generally ranging from 5 to 10 years. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings.

Leases:

The Company enters into operating leases for its office space in Houston and Midland, Texas. The Company recognizes lease expense on a straight-line basis over the lease term. Lease right-of-use assets and liabilities are initially recorded on the lease commencement date based on the present value of lease payments over the lease term. As the Company's lease contracts do not provide an implicit discount rate, the Company uses its incremental borrowing rate, which is determined based on information available at the commencement date of a lease. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. The exercise of those options is at the Company's sole discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with an initial term of 12 months or less are not recorded as a lease right-of-use asset and liability. See Note 5 for additional information.

Capitalization of Interest:

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated and successful.

Impairment of Long-Lived Assets:

The Company reviews long-lived assets, including oil and gas properties, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted cash flows, the assets are impaired, and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows.

Fair Value:

The Company follows the authoritative guidance that establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted accounting principles to be measured at fair value. The guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. The guidance establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

Revenue recognition:

The majority of the Company's production is operated by third party operators where we elect to market our products under the joint operating agreements. Accordingly, we receive our proportionate share of revenue proceeds for production sold by the operator under the operator's marketing agreements. The Company recognizes revenue and any costs indicated by the operator in the related production period.

The Company recognizes revenue related to production from properties operated by the Company when control of the promised goods or services is transferred to customers at an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

Oil sales. The Company recognizes oil sales revenue when (i) control/custody transfers to the purchaser and (ii) the agreed-upon index price, net of any price differentials, is fixed and determinable. Any costs incurred prior to the transfer of control to the customer, such as gathering and transportation costs, are recognized as oil and gas production costs.

NGL and gas sales. Under the majority of the Company's gas processing contracts, gas is delivered to a midstream processing entity and the Company recognizes revenue when the products are delivered to the midstream gathering or processing entity at a specified index price, net of downstream gathering and processing fees.

Field service income. The majority of the Company's services are performed under Master Service Agreements. The Company recognizes revenue when the products and services are provided to the customer.

Asset Retirement Obligation:

The asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate producing properties at the end of their productive lives, in accordance with applicable state laws. The Company determined its asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The asset retirement obligation is recorded as a liability at its estimated present value at its inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the statements of income.

Income Taxes:

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. As of December 31, 2023 and 2022, the Company had no valuation allowance.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

General and Administrative Expenses:

General and administrative expenses represent cost and expenses associated with the operation of the Company.

Earnings Per Common Share:

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods.

Statements of Cash Flows:

For purposes of the consolidated statements of cash flows, the Company considers short-term, highly liquid investments with original maturities of less than ninety days to be cash equivalents.

Concentration of Credit Risk:

The Company maintains significant banking relationships with financial institutions in the State of Texas. The Company limits its risk by periodically evaluating the relative credit standing of these financial institutions. The Company's oil and gas production purchasers consist primarily of independent marketers and major gas pipeline companies.

Hedging:

The Company periodically enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with applicable accounting standards for derivative instruments and hedging activities. Such standards require that applicable derivative instruments be measured at fair market value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting applicable effectiveness guidelines, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in the statements of income.

New accounting standards. In November 2023, the FASB issued Accounting Standards Update 2023-07, "Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures," which is effective for fiscal years beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024 with early adoption permitted. The amendments in this Accounting Standards Update are focused on reportable segment disclosure requirements, primarily related to significant segment expenses, and are required to be applied retrospectively to all prior periods presented in a company's consolidated financial statements.

In December 2023, the FASB issued Accounting Standards Update 2023-09, "Income Taxes (Topic 740): Improvements to Income Tax Disclosures," which is effective for fiscal years beginning after December 15, 2024 with early adoption permitted. The amendments in this Accounting Standards Update are focused on income tax disclosure requirements, primarily related to the income tax rate reconciliation and income taxes paid, with prospective application to a company's consolidated financial statements recommended.

The Company is currently assessing the impacts of these new accounting standards on its disclosures.

2. Acquisitions and Dispositions

2023 Transactions:

In the first quarter of 2023, the Company sold 7.8 surface acres in Midland County, Texas receiving gross proceeds of \$ 436,050 and recognizing a gain of \$ 47,000 .

In the second quarter of 2023, the Company acquired 55 net acres in the South Stiles area of Reagan County, Texas for \$ 605,000 , and in a separate agreement also in Reagan County, the Company sold 320 non-core acres for proceeds of \$ 6,000,000 . In addition, the Company sold 36.51 % interest in one well in Midland County, Texas for proceeds of \$ 60,000 .

In the third quarter of 2023, the Company sold a non-core 38.25 -acre leasehold tract in Martin County, Texas for proceeds of \$ 899,000 and sold 3 surface acres in Liberty County, Texas for net proceeds of \$ 37,053 . Also in the third quarter, in various counties of Oklahoma, the Company divested its interest in 39 wells, reducing its future plugging liability by approximately \$ 1.5 million. Effective July 1, 2023, the Company acquired the operations of 36 wells from DE Permian and 50 % of DE Permian's original ownership in such wells. In addition, in Reagan County, Texas, the Company acquired 114.52 net acres from DE Permian for \$ 1,700,853 and assigned to them 203.23 net acres.

In the fourth quarter of 2023, the Company sold 136 surface acres in Oklahoma for net proceeds of \$ 306,000 and in Midland Texas sold 9.35 net acres for proceeds of \$ 280,423 .

2022 Transactions:

In the first quarter of 2022, the Company sold 1,809 net leasehold acres in Reagan and Midland Counties, Texas through two separate transactions receiving gross proceeds of \$ 14.0 million. In the second quarter of 2022, the Company sold 241 net acres in Canadian County, Oklahoma for \$ 845,000 . In the third quarter of 2022, the Company sold an additional 113 net acres in Canadian County, Oklahoma for \$ 423,700 .

On November 14, 2022, the Company completed an acreage exchange of approximately 725 net acres in the Midland Basin creating a block of 1,200 contiguous acres. The Company entered into an agreement, including this acreage, to create a 2,560 -acre AMI for the joint development of horizontal wells. As part of the agreement, the Company sold a portion of its interest in this acreage to the joint development partner for proceeds of \$ 16.1 million.

3. Additional Balance Sheet Information

Accounts receivable, net at December 31, 2023 and 2022 consisted of the following:

(Thousands of dollars)	December 31,	
	2023	2022
Joint interest billings	\$ 2,560	\$ 1,806
Trade receivables	2,345	1,762
Oil and gas sales	14,457	8,894
Taxes	1,458	--
Other	155	21
	20,975	12,483
Less: Allowance for credit losses	(674)	(336)
Total	\$ 20,301	\$ 12,147

Accounts payable at December 31, 2023 and 2022 consisted of the following:

(Thousands of dollars)	December 31,	
	2024	2022
Trade	\$ 9,847	\$ 5,142
Royalty and other owners	4,405	3,600
Partner advances	946	1,111
Other	226	1,598
Total	\$ 15,424	\$ 11,451

Accrued liabilities at December 31, 2023 and 2022 consisted of the following:

(Thousands of dollars)	December 31,	
	2023	2022
Compensation and related expenses	\$ 10,324	\$ 9,743
Property costs	33,264	6,413
Taxes	929	9,352
Lease operating costs	3,898	1,695
Other	198	242
Total	\$ 48,613	\$ 25,750

4. Long-Term Debt

Bank Debt:

On July 5, 2022, the Company and its lenders entered into a Fourth Amended and Restated Credit Agreement (the "2022 Credit Agreement") with a maturity date of June 1, 2026. Under the 2022 Credit Agreement, the Company has a revolving line of credit and letter of credit facility of up to \$ 300 million subject to a borrowing base that is determined semi-annually by the lenders based upon the Company's consolidated financial statements and the estimated value of the Company's oil and gas properties, in accordance with the Lenders' customary practices for oil and gas loans. The initial borrowing base of the agreement is \$ 75 million. The credit facility is secured by substantially all of the Company's oil and gas properties. The 2022 Credit Agreement includes terms and covenants that require the Company to maintain a minimum current ratio and total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio, as defined, and restrictions are placed on the payment of dividends, the amount of treasury stock the Company may purchase, and commodity hedge agreements.

On December 31, 2022, the Company had a total of \$ 11 million of borrowings outstanding under its revolving credit facility and \$ 64 million was available for future borrowings.

Effective January 20, 2023, in lieu of a formal amendment, a borrowing base letter authorized by all lenders and the Company of the 2022 Credit Agreement resulted in an adjustment to decrease the amount of the Borrowing Base available from \$ 75 million to \$ 60 million until such time as the next redetermination date as required by the agreement.

Effective July 24, 2023, in lieu of a formal amendment, a borrowing base letter authorized by all lenders and the Company of the 2022 Credit Agreement resulted in an adjustment to increase the amount of the Borrowing Base available from \$60 million to \$ 65 million until such time as the next redetermination date as required by the agreement.

As of December 31, 2023, the borrowing base was \$ 65 million and the Company had no outstanding borrowings under the Credit Facility.

Effective February 9, 2024, the Company and its lenders entered into the Second Amendment to the 2022 Credit Agreement. This amendment included an increase of the Borrowing Base from \$65 million to \$ 85 million and will remain in effect until the next scheduled redetermination date in accordance with the Credit Agreement. As of March 31, 2024 the Company had \$ 4 million of outstanding borrowings and \$ 81 million available under the credit facility.

5. Other Long-Term Obligations and Commitments:

Operating Leases:

The Company leases office facilities under operating leases and recognizes lease expense on a straight-line basis over the lease term. Lease assets and liabilities are initially recorded at commencement date based on the present value of lease payments over the lease term. As most of the Company's lease contracts do not provide an implicit discount rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. The weighted average discount rate used was 6.96%. Certain leases may contain variable costs above the minimum required payments and are not included in the right-of-use assets or liabilities. Leases may include renewal, purchase or termination options that can extend or shorten the term of the lease. The exercise of those options is at the Company's sole discretion and is evaluated at inception and throughout the contract to determine if a modification of the lease term is required. Leases with an initial term of 12 months or less are not recorded on the balance sheet.

Operating lease costs for the years ended December 31, 2023 and 2022 were \$ 700 thousand and \$ 628 thousand, respectively. Cash payments included in the operating lease cost for years ended December 31, 2023 and 2022 were \$ 739 thousand and \$ 673 thousand, respectively. The weighted-average remaining operating lease terms for the years ended December 31, 2023 and 2022 were 11 months and 11 months, respectively. As of 2023, the Company had certain leases for office space in Texas which included future payments of \$ 275,000 in 2024 and \$ 45,000 in 2025.

On March 4, 2024 the Company entered into a twelve-month lease extension agreement, effective March 1, 2024, with the landlord of the Company's Houston office. Rent expense for office space for the years ended December 31, 2023 and 2022 was \$ 767,000 and \$ 755,000 , respectively.

The payment schedule for the Company's operating lease obligations as of December 31, 2023 is as follows:

<i>(Thousands of dollars)</i>	Operating Leases
2024	275
2025	45
Total undiscounted lease payments	\$ 320
Less: Amount associated with discounting	(36)
Total net operating lease liabilities	\$ 284
Less: Current portion included in Current portion of Asset Retirement and Other Long-Term Obligations	246
Non-current portion included in Other Long-Term Obligations	\$ 38

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2023 and 2022 is as follows:

<i>(Thousands of dollars)</i>	Years Ended December 31,	
	2023	2022
Asset retirement obligation at beginning of period	\$ 15,443	\$ 14,295
Net wells placed on production	254	11
Liabilities settled	(2,706)	(1,407)
Dispositions	(1,161)	(344)
Accretion expense	684	667
Revisions in estimated liabilities	2,639	2,221
Asset retirement obligation at end of period	\$ 15,153	\$ 15,443
Less: Current portion included in Current portion of asset retirement and other long-term obligations	446	1,918
Long-term Asset Retirement Obligations included in Asset Retirement Obligations	\$ 14,707	\$ 13,525

The Company's liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and a risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of the Company's wells, the costs to ultimately retire the wells may vary significantly from previous estimates.

6. Contingent Liabilities

The Company is subject to environmental laws and regulations. Management believes that future expenses, before recoveries from third parties, if any, will not have a material effect on the Company's financial condition. This opinion is based on expenses incurred to date for remediation and compliance with laws and regulations, which have not been material to the Company's results of operations.

From time to time, the Company is party to certain legal actions arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

7. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2023 and 2022, options on 767,500 shares were outstanding and exercisable at prices ranging from \$ 1.00 to \$ 1.25 . According to their terms, the options have no expiration date.

8. Income Taxes

The components of the provision for income taxes for the years ended December 31, 2023 and 2022 are as follows:

(Thousands of dollars)	Years Ended December 31,	
	2023	2022
Current:		
Federal	\$ (891)	\$ 8,330
State	(258)	774
Total current	(1,149)	9,104
Deferred:		
Federal	6,544	886
State	724	339
Total deferred	7,268	1,225
Total income tax provision	\$ 6,119	\$ 10,329

The components of net deferred tax assets and liabilities are as follows:

(Thousands of dollars)	At December 31,	
	2023	2022
Deferred Tax Assets:		
Accrued liabilities	\$ 349	\$ 353
Allowance for doubtful accounts	154	77
Derivative Contracts	-	223
Partnership basis difference	106	90
State Net operating loss carry-forwards	278	283
Total deferred tax assets	887	1,026
Deferred Tax Liabilities:		
Depletion and depreciation	48,123	40,994
Total deferred tax liabilities	48,123	40,994
Net deferred tax liabilities	\$ 47,236	\$ 39,968

The total provision for income taxes for the years ended December 31, 2023 and 2022 varies from the federal statutory tax rate as a result of the following:

(Thousands of dollars)	Years Ended December 31,	
	2023	2022
Expected tax expense	\$ 7,187	\$ 12,389
Permanent differences	221	870
State income tax, net of federal benefit	204	612
Provision to return adjustment	(1,534)	(3,540)
Other, net	41	(2)
Total income tax provision	\$ 6,119	\$ 10,329

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

The Company is entitled to percentage depletion on certain of its wells, which is calculated without reference to the basis of the property. To the extent that such depletion exceeds a property's basis, it creates a permanent difference, which lowers the Company's effective rate. The availability of the percentage depletion deduction is phased out as an entity's production exceeds certain levels, and based on the Company's increasing production the percentage depletion deduction is becoming less significant.

The Company is allowed a credit against the Texas Franchise Tax based on net operating losses incurred in prior periods. The credits allowed are \$ 89 thousand in the years 2023 through 2026. Any credits not utilized in a given year due to the allowable credit exceeding the tax liability may be carried forward. No credit may be carried forward past 2026. The value of the credit is calculated net of the federal income tax effect.

The Company has not recorded any provision for uncertain tax positions. The Company files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The 2004, 2005, 2006, 2009 and 2017 federal income tax returns have been audited by the Internal Revenue Service. Returns for unexamined earlier years may be examined and adjustments made to the amount of percentage depletion and AMT credit carryforwards flowing from those years into an open tax year, although in general no assessment of income tax may be made for those years on which the statute has closed. Federal and State returns for the years 2020 through 2022 remain open for examination by the relevant taxing authorities.

Enactment of the Inflation Reduction Act of 2022.

On August 16, 2022, President Biden signed into law the Inflation Reduction Act of 2022 (the "IRA"), which includes, among other things, a corporate alternative minimum tax (the "CAMT"). Under the CAMT, a 15 percent minimum tax will be imposed on certain adjusted financial statement income of "applicable corporations," which is effective for tax years beginning after December 31, 2022. The CAMT generally treats a corporation as an "applicable corporation" in any taxable year in which the "average annual adjusted financial statement income" of the corporation and certain of its subsidiaries and affiliates for a three taxable-year period ending prior to such taxable year exceeds \$1 billion. The IRA also establishes a one percent excise tax on stock repurchases made by publicly traded U.S. corporations. The excise tax is effective for any stock repurchases after December 31, 2022. The value of share repurchases subject to the excise tax is reduced by the fair market value of any shares issued during the tax year, including the fair market value of any shares issued or provided to employees or specified affiliates. During the year ended December 31, 2023, the Company recorded \$ 74 thousand related to the IRA excise tax payable on share repurchases.

9. Segment Information and Major Customers

The Company operates in one industry – oil and gas exploration, development, operation and servicing. The Company's oil and gas activities are entirely in the United States. The Company sells its oil and natural gas and liquids production to a number of direct purchasers under direct contracts or through other operators under joint operating agreements. Listed below are the purchasers of the Company's production which represented more than 10 % of the Company's sales for the years ended 2023 and 2022.

	2023	2022
Oil:		
APA Corporation	22%	55%
Civitas Resources Inc.	20%	--%
Plains All American Inc.	19%	16%
DE IV Operating, LLC.	14%	--%
Natural gas and liquids:		
APA Corporation	17%	58%
Civitas Resources Inc.	10%	--%
Targa Pipeline Mid-Continent West Tex, LLC	--%	11%

Although there are no long-term oil and gas purchasing agreements with these purchasers, the Company believes that they will continue to purchase its oil and gas products and, if not, could be replaced by other purchasers.

10. Financial Instruments

Fair Value Measurements:

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value. The fair values of the Company's interest rate swaps, natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company's assets and liabilities measured at fair value on a recurring basis at December 31, 2022:

December 31, 2022	Quoted Prices in Active Markets For Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2022
<i>(Thousands of dollars)</i>				
Assets				
Commodity derivative contracts	\$ —	\$ —	\$ 210	\$ 210
Total assets	\$ —	\$ —	\$ 210	\$ 210
Liabilities				
Commodity derivative contract	\$ —	\$ —	\$ (1,190)	\$ (1,190)
Total liabilities	\$ —	\$ —	\$ (1,190)	\$ (1,190)

The derivative contracts were measured based on quotes from the Company's counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using comparable NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties' valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 2023.

<i>(Thousands of dollars)</i>	
Net Liabilities – December 31, 2022	\$ (980)
Total realized and unrealized gains	980
Net Liabilities – December 31, 2023	\$ —

- (a) Derivative instruments are reported in revenues as realized gain/loss and on a separately reported line item captioned unrealized gain/loss on derivative instruments.

Derivative Instruments:

The Company is exposed to commodity price and interest rate risk, and management considers periodically the Company's exposure to cash flow variability resulting from the commodity price changes and interest rate fluctuations. Futures, swaps and options are used to manage the Company's exposure to commodity price risk inherent in the Company's oil and gas production operations. The Company does not apply hedge accounting to any of its commodity-based derivatives. Both realized and unrealized gains and losses associated with commodity derivative instruments are recognized in earnings.

The following table sets forth the effect of derivative instruments on the consolidated balance sheets at December 31, 2023 and 2022:

(Thousands of dollars)	Balance Sheet Location	Fair Value	
		December 31, 2023	December 31, 2022
Asset Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contract	Other current assets	\$ —	\$ 162
Natural gas commodity contract	Other current assets	—	48
Total		<u>\$ —</u>	<u>\$ 210</u>
Liability Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative liability short-term	\$ —	\$ (931)
Natural gas commodity contracts	Derivative liability short-term	—	(259)
Total		<u>\$ —</u>	<u>\$ (1,190)</u>
Total derivative instruments		<u>\$ —</u>	<u>\$ (980)</u>

The following table sets forth the effect of derivative instruments on the consolidated statements of income for the years ended December 31, 2023 and 2022:

		Amount of gain/loss recognized in income	
(Thousands of dollars)	Location of gain/loss recognized in income	2023	2022
Derivatives not designated as cash-flow hedge instruments:			
Natural gas commodity contracts	Unrealized gain on derivative instruments, net	—	892
Crude oil commodity contracts	Unrealized gain on derivative instruments, net	—	3,713
Natural gas commodity contracts	Realized gain (loss) on derivative instruments, net	235	(4,543)
Crude oil commodity contracts	Realized gain (loss) on derivative instruments, net	179	(12,101)
		\$ 414	\$ (12,039)

11. Related Party Transactions

Amounts due to or from related parties primarily represent receipts or expenses, related to oil and gas properties, collected or paid by the Company as agent for the joint venture partners, which may include members of the Company's Board of Directors.

12. Salary Deferral Plan

The Company maintains a salary deferral plan (the "Plan") in accordance with Internal Revenue Code Section 401(k), as amended. The Plan provides for matching contributions, of which \$ 362,756 and \$ 301,837 were made in 2023 and 2022, respectively.

13. Earnings per Share

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods. The following reconciles amounts reported in the consolidated financial statements:

	Years Ended December 31,					
	2023			2022		
	Net Income (In 000's)	Weighted Average Number of Shares Outstanding	Per Share Amount	Net Income (In 000's)	Weighted Average Number of Shares Outstanding	Per Share Amount
Basic	\$ 28,103	1,849,780	\$ 15.19	\$ 48,664	1,953,916	\$ 24.91
Effect of dilutive securities:						
Options	—	759,006	—	—	757,254	—
Diluted	\$ 28,103	2,608,786	\$ 10.77	\$ 48,664	2,711,170	\$ 17.95

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

CAPITALIZED COSTS RELATING TO
OIL AND GAS PRODUCING ACTIVITIES

(Unaudited)

(Thousands of dollars)	As of December 31,	
	2023	2022
Proved Developed oil and gas properties	\$ 659,792	\$ 555,280
Proved Undeveloped oil and gas properties	—	—
Total Capitalized Costs	659,792	555,280
Accumulated depreciation, depletion and valuation allowance	(406,913)	(385,811)
Net Capitalized Costs	\$ 252,879	\$ 169,469

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,
EXPLORATION AND DEVELOPMENT ACTIVITIES

(Unaudited)

(Thousands of dollars)	Years Ended December 31,	
	2023	2022
Development Costs	\$ 110,700	\$ 13,598

STANDARDIZED MEASURE OF DISCOUNTED FUTURE
NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

(Unaudited)

(Thousands of dollars)	As of December 31,	
	2023	2022
Future cash inflows	\$ 1,219,605	\$ 994,842
Future production costs	(437,408)	(378,160)
Future development costs	(213,823)	(95,746)
Future income tax expenses	(119,359)	(110,439)
Future Net Cash Flows	449,015	410,497
10% annual discount for estimated timing of cash flows	(170,967)	(165,961)
Standardized Measure of Discounted Future Net Cash Flows	\$ 278,048	\$ 244,536

See accompanying Notes to Supplementary Information

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

STANDARDIZED MEASURE OF DISCOUNTED FUTURE
NET CASH FLOWS AND CHANGES THEREIN
RELATING TO PROVED OIL AND GAS RESERVES

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2023 and 2022:

<i>(Thousands of dollars)</i>	Years Ended December 31,	
	2023	2022
Sales of oil and gas produced, net of production costs	\$ (107,742)	\$ (86,302)
Net changes in prices and production costs	(98,132)	72,640
Extensions, discoveries and improved recovery	178,960	126,029
Revisions of previous quantity estimates	(3,877)	(10,902)
Net change in development costs	66,552	(2,814)
Reserves sold	(398)	(818)
Reserves purchased	—	—
Accretion of discount	24,454	13,581
Net change in income taxes	4,532	(8,435)
Changes in production rates (timing) and other	(30,836)	5,751
Net change	33,512	108,730
Standardized measure of discounted future net cash flow:		
Beginning of year	244,536	135,806
End of year	<u>\$ 278,048</u>	<u>\$ 244,536</u>

See accompanying Notes to Supplementary Information

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESERVE QUANTITY INFORMATION
Years Ended December 31, 2023 and 2022

(Unaudited)

	As of December 31,					
	2023			2022		
	Oil (MBbls)	NGL's (MBbls)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)
Proved Developed Reserves:						
Beginning of year	4,143	2,497	22,277	5,386	2,882	23,902
Extensions, discoveries and improved recovery	843	467	2,391	99	74	464
Revisions of previous estimates	(1,101)	(515)	(4,796)	(375)	(37)	1,309
Converted from undeveloped reserves	3,028	1,833	9,030	—	—	—
Reserves sold	(12)	—	(26)	(28)	(5)	(73)
Reserve purchased	—	—	—	—	—	—
Production	(1,144)	(606)	(4,127)	(939)	(417)	(3,325)
End of year	5,757	3,676	24,749	4,143	2,497	22,277
Proved Undeveloped Reserves:						
Beginning of year	3,028	1,833	9,030	—	—	—
Extensions, discoveries and improved recovery	6,254	5,156	24,470	3,028	1,833	9,030
Revisions of previous estimates	—	—	—	—	—	—
Converted to developed reserves	(3,028)	(1,833)	(9,030)	—	—	—
Reserves Sold	—	—	—	—	—	—
End of year	6,254	5,156	24,470	3,028	1,833	9,030
Total Proved Reserves at the End of the Year	12,011	8,832	49,219	7,171	4,330	31,307

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES
Years Ended December 31, 2023 and 2022

(Unaudited)

(Thousands of dollars)	Years Ended December 31,	
	2023	2022
Revenue:		
Oil and gas sales	\$ 107,742	\$ 124,118
Costs and Expenses:		
Lease operating expenses	39,004	37,816
Depreciation, depletion and accretion	31,660	28,068
Income tax expense	5,797	10,329
Total Costs and Expenses	76,461	76,213
Results of Operations from Producing Activities (excluding corporate overhead and interest costs)	\$ 31,281	\$ 47,905

See accompanying Notes to Supplementary Information

PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

**NOTES TO SUPPLEMENTARY INFORMATION
(Unaudited)**

1. Presentation of Reserve Disclosure Information

Reserve disclosure information is presented in accordance with U.S. generally accepted accounting principles. The Company's reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of the Company's reserves.

2. Determination of Proved Reserves

The estimates of the Company's proved reserves were determined by an independent petroleum engineer in accordance with U.S. generally accepted accounting principles. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development and other factors. Estimated future net revenues were computed by reserves, less estimated future development and production costs based on current costs.

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that proved reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

3. Results of Operations from Oil and Gas Producing Activities

The results of operations from oil and gas producing activities were prepared in accordance with U.S. generally accepted accounting principles. General and administrative expenses, interest costs and other unrelated costs are not deducted in computing results of operations from oil and gas activities.

4. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes of standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with U.S. generally accepted accounting principles.

Future cash inflows are computed as described in Note 2 by applying current prices to year-end quantities of proved reserves.

Future production and development costs are computed estimating the expenditures to be incurred in developing and producing the oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying the U.S. tax rate to future pre-tax cash inflows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences and tax credits and allowances relating to the proved oil and gas reserves.

Future net cash flows are discounted at a rate of 10% annually (pursuant to applicable guidance) to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily represent an estimate of fair market value or the present value of such cash flows since future prices and costs can vary substantially from year-end and the use of a 10% discount figure is arbitrary.

5. Changes in Reserves

The 2023 and 2022 extensions and discoveries reflect the drilling activity in the Company's West Texas and Mid-Continent areas. The Company is employing technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of its proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques. Future development plans are reflective of the current commodity prices and have been established based on an expectation of available cash flows from operations and availability under our revolving credit facility.

PRIMEENERGY RESOURCES CORPORATION**DESCRIPTION OF SECURITIES REGISTERED
PURSUANT TO SECTION 12 OF THE
SECURITIES EXCHANGE ACT OF 1934**

The common stock of PrimeEnergy Resources Corporation ("we," "us" and "our") is listed and principally traded on the Nasdaq Stock Market ("Nasdaq") under the ticker symbol "PNRG." Our authorized capital stock consists of 2,810,000 shares of common stock, par value \$0.10 per share.

The following summary of the material terms of our capital stock, Restated Certificate of Incorporation (the "certificate of incorporation") and Amended and Restated Bylaws (the "bylaws") does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our certificate of incorporation and bylaws.

Common Stock

Each share of common stock entitles the holder to one vote on all matters on which holders are permitted to vote, including the election of directors. There are no cumulative voting rights. Accordingly, holders of a plurality of the total votes entitled to vote in an election of directors will be able to elect all of the directors standing for election. The holders of the common stock will share equally on a per share basis any dividends when, as and if declared by the board of directors out of funds legally available for that purpose. If we are liquidated, dissolved or wound up, the holders of our common stock will be entitled to a ratable share of any distribution to stockholders, after satisfaction of all of our liabilities. Our common stock has no preemptive or conversion rights or other subscription rights. There are no redemption or sinking fund provisions applicable to our common stock. All outstanding shares of our common stock are fully paid and nonassessable.

Election and Removal of Directors

Our board of directors must consist of not less than three nor more than fifteen members. The exact number of directors is fixed from time to time by resolution of the board. Each director shall be elected by a plurality of the votes cast at each annual meeting of stockholders and each director so elected shall hold office until the next annual meeting of stockholders and until such director's successor is duly elected and qualified, or until such director's earlier death, resignation or removal. In addition, any director or the entire Board of Directors may be removed from office at any time, with or without cause, by the affirmative vote of the holders of at least a majority in voting power of our issued and outstanding capital stock. Any vacancy occurring on the board of directors or any committee thereof may be filled only by a majority of the directors then in office, though less than a quorum, or by a sole remaining director.

Stockholder Meetings

Our bylaws provide that special meetings of our stockholders may be called by either the chairman of our board of directors, if there be one, or by our president or secretary, and shall be called by any such officer at the request in writing of our board of directors, a committee of our board of directors that has been duly designated by the board of directors and whose powers and authority include the power to call such meetings, or stockholders owning a majority of our capital stock issued and outstanding and entitled to vote on the matter for which such special meeting of stockholders is called.

Stockholder Action by Written Consent

Our certificate of incorporation provides that any action required or permitted to be taken at any annual or special meeting of the stockholders by the stockholders of our company may be taken without a meeting, without prior notice and without a vote, if a consent or consents in writing, setting forth the action so taken, shall be executed by the holders of outstanding stock having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Amendment of Bylaws

Our bylaws may generally be altered, amended or repealed, in whole or in part, and new bylaws may be adopted, by approval of either the holders of a majority of the outstanding capital stock entitled to vote thereon or by a majority of our board of directors then in office.

Advance Notice Requirements for Stockholder Proposals and Director Nominations

Our Bylaws provide that stockholders seeking to bring business before an annual meeting of stockholders, or to nominate candidates for election as directors at an annual or special meeting of stockholders, must provide timely notice to us thereof in writing within the time periods specified in our Bylaws. Our Bylaws also specify requirements as to the form and content of a stockholder's notice.

Limitation on Liability of Directors

No person serving as a director of our board of directors shall have any personal liability to us or our stockholders for monetary damages for breach of fiduciary duty as a director, provided that, such restriction on personal liability shall not eliminate or limit the liability of a director (i) for any breach of the director's duty of loyalty to us or our stockholders, (ii) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (iii) for unlawful payment of any dividend or unlawful stock purchase or redemption under Section 174 of the Delaware General Corporation Law ("DGCL"); or (iv) for any transaction from which the director derived an improper personal benefit.

Our bylaws provide that, to the fullest extent permitted by law, we will indemnify any officer or director of our company against all damages, claims and liabilities arising out of the fact that the person is or was our director or officer, or served another corporation, partnership, joint venture, trust or other enterprise at our request as a director, officer, employee or agent.

Expenses, including attorneys' fees, incurred by our directors or officers in defending any civil, criminal, administrative or investigative action, suit or proceeding shall be paid by us in advance of the final disposition of such action, suit or proceeding upon receipt of an undertaking by or on behalf of such director or officer to repay such amount if it shall ultimately be determined that such person is not entitled to be indemnified by us. Such expenses, including attorneys' fees, incurred by our former directors and officers or other employees and agents or by persons serving at our request as directors, officers, employees or agents of another corporation, partnership, joint venture, trust or other enterprise may be so paid upon such terms and conditions, if any, as we deem appropriate.

Anti-Takeover Effects of Delaware Law

We are a Delaware corporation and are subject to Section 203 of the DGCL. Section 203 provides that we may not engage in a broad range of "business combinations" with any "interested stockholder" for a three-year period following the time that the person became an interested stockholder unless:

- prior to the time that person became an interested stockholder, our board of directors had approved either the business combination or the transaction that resulted in the person becoming an interested stockholder;
- upon consummation of the transaction that resulted in the person becoming an interested stockholder, that person owned at least 85% of our voting stock outstanding at the time the transaction commenced, excluding shares owned by persons who are directors and also officers and shares owned in employee stock plans in which participants do not have the right to determine confidentially whether shares held subject to the plan will be tendered in a tender or exchange offer; or
- at or subsequent to the time that person became an interested stockholder, the business combination is approved by our board of directors and by the affirmative vote of at least 66 2/3% of the outstanding voting stock that is not owned by the interested stockholder.

Generally, a business combination includes a merger, consolidation, asset or stock sale or other transaction resulting in a financial benefit to the interested stockholder. Subject to certain exceptions, an interested stockholder is a person who, together with that person's affiliates and associates, owns, or within the previous three years owned, 15% or more of our voting stock. Under Section 203, the restrictions described above also do not apply to specific business combinations proposed by an interested stockholder following the announcement or notification of designated extraordinary transactions involving the corporation and a person who had not been an interested stockholder during the previous three years or who became an interested stockholder with the approval of a majority of the corporation's directors, if such extraordinary transaction is approved or not opposed by a majority of the directors who were directors prior to any person becoming an interested stockholder during the previous three years or were recommended for election or elected to succeed such directors by a majority of such directors.

Section 203 could prohibit or delay mergers or other takeover or change in control attempts with respect to us and, accordingly, may discourage attempts to acquire us.

Transfer Agent and Registrar

We may from time to time maintain one or more transfer offices or agencies and registry offices or agencies at such place or places as may be determined from time to time by the board of directors, subject to the rules and regulations of any securities exchange or quotation system on which our securities are listed or quoted for trading.

SUBSIDIARIES

PrimeEnergy Management Corporation, a New York corporation, 100% owned by PrimeEnergy Resources Corporation.

Prime Operating Company, a Texas corporation, 100% owned by PrimeEnergy Resources Corporation.

Eastern Oil Well Service Company, a West Virginia corporation, 100% owned by PrimeEnergy Resources Corporation.

EOWS Midland Company, a Texas corporation, 100% owned by PrimeEnergy Resources Corporation.

Prime Offshore L.L.C., a Delaware limited liability company, 100% owned by PrimeEnergy Resources Corporation.



TBPELS REGISTERED ENGINEERING FIRM F-1580

633 17TH STREET SUITE 1700 DENVER, COLORADO 80202

TELEPHONE (303) 339-8110

CONSENT OF RYDER SCOTT COMPANY, L.P.

We consent to the filing of our summary reserve report dated March 12, 2024, as Exhibit 23 to the PrimeEnergy Corporation annual report on Form 10-K for the year ended December 31, 2023 and to any reference made to us on that form 10-K.

Very Truly Yours,

/s/ Ryder Scott Company, L.P.
Ryder Scott Company, L.P.

Denver, Colorado
April 15, 2024

CERTIFICATIONS

I, Charles E. Drimal, Jr., Chief Executive Officer of PrimeEnergy Resources Corporation, certify that:

1. I have reviewed this Form 10-K for the year ended December 31, 2023, of PrimeEnergy Resources Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of 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.

April 15, 2024

/s/ Charles E. Drimal, Jr.
Charles E. Drimal, Jr.
Chief Executive Officer
PrimeEnergy Resources Corporation

CERTIFICATIONS

I, Beverly A. Cummings, Chief Financial Officer of PrimeEnergy Resources Corporation, certify that:

1. I have reviewed this Form 10-K for the year ended December 31, 2023, of PrimeEnergy Resources Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of 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.

April 15, 2024

/s/ Beverly A. Cummings
Beverly A. Cummings
Chief Financial Officer
PrimeEnergy Resources Corporation

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

In connection with the Annual Report of PrimeEnergy Resources Corporation (the "Company") on Form 10-K for the period ending December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charles E. Drimal Jr., Chief Executive Officer of PrimeEnergy Resources Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

/s/ Charles E. Drimal, Jr.

Charles E. Drimal, Jr.
Chief Executive Officer
April 15, 2024

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

In connection with the Annual Report of PrimeEnergy Resources Corporation (the "Company") on Form 10-K for the period ending December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Beverly A. Cummings, Chief Financial Officer of PrimeEnergy Resources Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

/s/ Beverly A. Cummings

Beverly A. Cummings
Chief Financial Officer
April 15, 2024

PrimeEnergy Resources Corporation
COMPENSATION RECOUPMENT (CLAWBACK) POLICY

Recoupment of Incentive-Based Compensation

It is the policy of PrimeEnergy Resources Corporation (the "Company") that, in the event the Company is required to prepare an accounting restatement of the Company's financial statements due to the Company's material non-compliance with any financial reporting requirement under the federal securities laws (including any such correction that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period), the Company will recover on a reasonably prompt basis the amount of any Incentive-Based Compensation Received by a Covered Executive during the Recovery Period that exceeds the amount that otherwise would have been received had it been determined based on the restated financial statements.

Policy Administration and Definitions

This Policy is administered by the Compensation Committee (the Committee) of the Company's Board of Directors, subject to ratification by the independent members of the Board of Directors with respect to application of this Policy to the Company's Chief Executive Officer, and is intended to comply with, and as applicable to be administered and interpreted consistent with, and subject to the exceptions set forth in, Listing Standard 5608 adopted by The Nasdaq Stock Market] to implement Rule 10D-1 under the Securities Exchange Act of 1934, as amended (collectively, "Rule 10D-1").

For purposes of this Policy:

"Incentive-Based Compensation" means any compensation granted, earned, or vested based in whole or in part on the Company's attainment of a financial reporting measure that was Received by a person (i) on or after October 2, 2023 and after the person began service as a Covered Executive, and (ii) who served as a Covered Executive at any time during the performance period for the Incentive-Based Compensation. A financial reporting measure is (i) any measure that is determined and presented in accordance with the accounting principles used in preparing the Company's financial statements and any measure derived wholly or in part from such a measure, and (ii) any measure based in whole or in part on the Company's stock price or total shareholder return.

Incentive-Based Compensation is deemed to be "Received" in the fiscal period during which the relevant financial reporting measure is attained, regardless of when the compensation is actually paid or awarded.

"Covered Executive" means "officer" of the Company as defined under Rule 16a-1(f) under the Securities Exchange Act of 1934, as amended.

"Recovery Period" means the three completed fiscal years immediately preceding the date that the Company is required to prepare the accounting restatement described in this Policy, all as determined pursuant to Rule 10D-1, and any transition period of less than nine months that is within or immediately following such three fiscal years.

If the Committee determines the amount of Incentive-Based Compensation Received by a Covered Executive during a Recovery Period exceeds the amount that would have been received if determined or calculated based on the Company's restated financial results, such excess amount of Incentive-Based Compensation shall be subject to recoupment by the Company pursuant to this Policy. For Incentive-Based Compensation based on stock price or total shareholder return, where the amount of erroneously awarded compensation is not subject to mathematical recalculation directly from the information in an accounting restatement, the Committee will determine the amount based on a reasonable estimate of the effect of the accounting restatement on the relevant stock price or total shareholder return. In all cases, the calculation of the excess amount of Incentive-Based Compensation to be recovered will be determined without regard to any taxes paid with respect to such compensation. The Company will maintain and will provide to The Nasdaq Stock Market documentation of all determinations and actions taken in complying with this Policy. Any determinations made by the Committee under this Policy shall be final and binding on all affected individuals.

The Company may effect any recovery pursuant to this Policy by requiring payment of such amount(s) to the Company, by set-off, by reducing future compensation, or by such other means or combination of means as the Committee determines to be appropriate. The Company need not recover the excess amount of Incentive-Based Compensation if and to the extent that the Committee determines that such recovery is impracticable, subject to and in accordance with any applicable exceptions under The NASDAQ Stock Market listing rules, and not required under Rule 10D-1, including if the Committee determines that the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered after making a reasonable attempt to recover such amounts. The Company is authorized to take appropriate steps to implement this Policy with respect to Incentive-Based Compensation arrangements with Covered Executives.

Any right of recoupment or recovery pursuant to this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Company pursuant to the terms of any other policy, any employment agreement or plan or award terms, and any other legal remedies available to the Company; provided that the Company shall not recoup amounts pursuant to such other policy, terms or remedies to the extent it is recovered pursuant to this Policy. The Company shall not indemnify any Covered Executive against the loss of any Incentive-Based Compensation (or provide any advancement of expenses in such instance), including any payment or reimbursement for the cost of third-party insurance purchased by any Covered Executives to fund potential recovery obligations under this Policy.

PrimeEnergy Resources Corporation

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold and Royalty Interests

SEC Parameters

As of

December 31, 2023

/s/ Clark D. Parrott

Clark D. Parrott, P.E.

Colorado License No. 35262

Vice President

[SEAL]

RYDER SCOTT COMPANY, L.P.

TBPELS Firm Registration No. F-1580



TBPELS REGISTERED ENGINEERING FIRM F-1580
633 17TH STREET SUITE 170 DENVER, COLORADO 80202 TELEPHONE (303) 339-8110

March 12, 2024

PrimeEnergy Resources Corporation
9821 Katy Freeway, Suite 1050
Houston, TX 77024

Dear Ms. Beverly A. Cummings,

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 PrimeEnergy Resources Corporation (PrimeEnergy) as of December 31, 2023. The subject properties are located in the states of Colorado, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Texas, West Virginia and Wyoming. 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 March 12, 2024 and presented herein, was prepared for public disclosure by PrimeEnergy in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon and gas reserves of PrimeEnergy 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, 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.

1100 LOUISIANA, SUITE 4600	HOUSTON, TEXAS 77002-5294	TEL (713) 651-9191	FAX (713) 651-0849
SUITE 2800, 350 7TH	CALGARY, ALBERTA T2P 3N9	TEL (403) 262-2799	
AVENUE, S.W.			

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold and Royalty Interests of
PrimeEnergy Resources Corporation and 100% of Partnership Interests
As of December 31, 2023

As of December 31, 2023				
	Proved			
	Developed		Undeveloped	Total Proved
	Producing	Non-Producing		
Net Reserves				
Oil/Condensate – Mbbl	4,942	815	6,254	12,011
Plant Products – Mbbl	3,299	377	5,156	8,832
Gas – MMcf	22,233	2,516	24,470	49,219
Income Data (\$M)				
Future Gross Revenue	\$ 473,588	\$ 72,898	\$ 607,664	\$ 1,154,150
Deductions	212,351	19,720	353,705	585,776
Future Net Income (FNI)	\$ 261,237	\$ 53,178	\$ 253,959	\$ 568,374
Discounted FNI @ 10%	\$ 174,405	\$ 38,876	\$ 138,679	\$ 351,960

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). 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 PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants L.C. The program was used at the request of PrimeEnergy. 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, recompletion costs, development costs and certain abandonment costs net of salvage. 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 92 percent and gas reserves account for the remaining 8 percent of total future gross revenue from proved reserves. “Other” future gross revenue, is de minimis, and is a result of the net profits interest in a few wells.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded annually. Future net income was discounted at four other discount rates, which were also compounded annually. These results are shown in summary form as follows.

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Discount Rate Percent	Discounted Future Net Income (\$M) As of December 31, 2023
	Total Proved
5	\$434,497
9	\$365,835
15	\$295,914
20	\$255,232

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 reserves included herein consist of the behind pipe and shut-in status categories and include new wells in their final stages of completion and waiting on facility connection.

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 PrimeEnergy'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.

PrimeEnergy'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 PrimeEnergy 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. In general, reserves attributable to producing wells and/or reservoirs were estimated by decline curve analysis, a performance method which utilized extrapolations of historical production and pressure data available through December 2023 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by PrimeEnergy and were considered sufficient for the purpose thereof. In certain early-life cases, producing reserves were estimated by analogy. This method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserves estimates was considered to be inappropriate.

The reserves for the properties included herein attributable to the non-producing, behind pipe status category were estimated by the volumetric method. The reserves for the non-producing, shut-in and undeveloped status categories were estimated by analogy. These analyses utilized pertinent well data furnished to Ryder Scott by PrimeEnergy that were available through December 2023. The data utilized from the analogues as well as the well data incorporated into our volumetric analysis were considered sufficient for the purpose thereof.

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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.

PrimeEnergy 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 PrimeEnergy 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, recompletion and development costs, development plans, certain abandonment costs after salvage, 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 PrimeEnergy. 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 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 wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by PrimeEnergy. Wells or 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 wells 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.

Ryder Scott furnished 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.

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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 PrimeEnergy and accepted as factual data.

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				
United States	Oil/Condensate	WTI Cushing	\$78.22/bbl	\$78.64/bbl
	NGL	WTI Cushing	\$78.22/bbl	\$19.64/bbl
	Gas	Henry Hub	\$2.64/MMBTU	\$2.06/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 PrimeEnergy and are based on the operating expense reports of PrimeEnergy and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and 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 PrimeEnergy. 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 PrimeEnergy 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.

The estimated net cost of abandonment after salvage was included for properties where certain abandonment costs net of salvage were provided by PrimeEnergy and for which they requested be included in our report. The estimates of the net abandonment costs furnished by PrimeEnergy were accepted without independent verification. We have made no inspections to determine if any additional abandonment, decommissioning, and /or restoration costs may be necessary in addition to the costs provided by PrimeEnergy and included herein.

The proved developed non-producing and undeveloped reserves in this report have been incorporated herein in accordance with PrimeEnergy's plans to develop these reserves as of December 31, 2023. The implementation of PrimeEnergy's development plans as presented to us and incorporated herein is subject to the approval process adopted by PrimeEnergy's management. As the result of our inquiries during the course of preparing this report, PrimeEnergy has informed us that the development activities included herein have been subjected to and received the internal approvals required by PrimeEnergy'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 PrimeEnergy. PrimeEnergy has provided written documentation supporting their commitment to proceed with the development activities as presented to us. Additionally, PrimeEnergy 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.

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Current costs used by PrimeEnergy 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 PrimeEnergy. 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 PrimeEnergy.

We have provided PrimeEnergy 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 PrimeEnergy 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
/s/ Clark D. Parrott
Clark D. Parrott, P.E. [SEAL]
Colorado License No. 35262
Vice President

CDP (DRO)/pl

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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. Clark D. Parrott was the primary technical person responsible for overseeing the estimate of the reserves, future production and income prepared by Ryder Scott presented herein.

Mr. Parrott, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2013 is a Vice President responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies throughout North America. Before joining Ryder Scott, Mr. Parrott served in a number of engineering positions with operators in the Rocky Mountain and Mid Continent regions. For more information regarding Mr. Parrott's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Parrott earned a Bachelor of Science degree in Petroleum Engineering from Colorado School of Mines in 1987 and is a registered Professional Engineer in the State of Colorado. He is a member of the Society of Petroleum Engineers.

Based on his educational background, professional training and more than 30 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Parrott 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.

RYDER SCOTT COMPANY PETROLEUM CONSULTANTS

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 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. 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.*
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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.