REFINITIV

DELTA REPORT

10-K

REI - RING ENERGY, INC.

10-K - DECEMBER 31, 2023 COMPARED TO 10-K - DECEMBER 31, 2022

The following comparison report has been automatically generated

TOTAL DELTAS	3896
CHANGES	379
DELETIONS	1174
ADDITIONS	2343

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2022 2023

Or

o **Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

For the transition period from ______ to ______

Commission file number 001-36057

Ring Energy, Inc.

(Exact name of registrant as specified in its charter)

Nevada	**90-0406406**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1725 Hughes Landing Blvd., Suite 900 The Woodlands, TX	**77380**
(Address of principal executive offices)	(Zip Code)

(281) 397-3699

(Registrant's telephone number, including area code)

Securities registered under Section 12(b) of the Exchange Act:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, par value $0.001	REI	NYSE American

Securities registered under Section 12(g) of the Exchange Act: **None**

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See 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	o		Accelerated filer	x
Non-accelerated filer	o	(Do not check if a smaller reporting company)	Smaller reporting company	o
Emerging growth company	o			

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

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. x

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 shell company (as defined in Rule 12b-2 of the Act). Yes o No x

As of June 30, 2022 June 30, 2023, the aggregate market value of the common voting stock held by non-affiliates of the registrant, based upon the closing stock price on that day on the NYSE American of $2.66 $1.71 per share, was $281,212,950. $227,493,793.

As of March 9, 2023 March 7, 2024, the registrant had outstanding 180,627,484 197,934,202 shares of common stock ($0.001 par value).

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Report, to the extent not set forth herein, is incorporated herein by reference from the registrant's definitive proxy statement relating to the Annual Meeting of Stockholders to be held in 2023, 2024, which definitive proxy statement shall be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Report relates.

TABLE OF CONTENTS

Forward Looking Statements

This Annual Report on Form 10-K (herein, “Annual Report”) contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements, other than statements of historical fact included in this Annual Report regarding our strategy, future operations, financial position, estimated revenues and expenses, projected costs, prospects, plans, and objectives of management are forward-looking statements. When used in this Annual Report, the words “may,” “will,” “could,” “would,” “should,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “plan,” “pursue,” “target,” “continue,” “potential,” “guidance,” “project” “project,” or other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. All forward-looking statements speak only as of the date of this Annual Report. Although we believe that our plans, intentions, and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report are reasonable, we can give no assurance that these plans, intentions, or expectations will be achieved. We are making investors aware that such forward-looking statements, because they relate to future events, are by their very nature subject to many important factors that could cause actual results to differ materially from those contemplated. Such factors include:

- declines or volatility in the prices we receive for our oil and natural gas;

- our ability to raise additional capital to fund future capital expenditures;
- our ability to generate sufficient net cash flow from operations, provided by operating activities, borrowings, or other sources to enable us to fully develop and produce our oil and natural gas properties;
- general economic conditions, whether internationally, nationally, or in the regional and local market areas in which we do business;
- risks associated with drilling, including completion risks, cost overruns, mechanical failures, and the drilling of non-economic wells or dry holes;
- uncertainties associated with estimates of proved oil and natural gas reserves;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the effects of inflation on our cost structure;
- substantial declines in the estimated values of our proved oil and natural gas reserves;
- our ability to replace our oil and natural gas reserves;
- the effects of rising interest rates on our cost of capital and the actions that central banks around the world undertake to control inflation, including the impacts such actions have on general economic conditions;
- risks and liabilities associated with acquired companies and properties;
- risks related to integration of acquired companies and properties;
- potential defects unanticipated reductions in title to the borrowing base under our properties; credit agreement;
- cost and availability of drilling rigs, equipment, supplies, personnel and oilfield services;
- geological concentration of our reserves;

- the potential for production decline rates and associated production costs for our wells to be greater than we forecast;
- risks and liabilities associated with the acquisition and integration of companies and properties;
- cost and availability of drilling rigs, and related equipment, supplies, personnel, and oilfield services;
- geological concentration of our oil and natural gas reserves;

- the timing and extent of our success in acquiring, discovering, developing, and producing oil and natural gas reserves;
- the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits;
- the possibility that potential divestitures may not occur or could be burdened with unforeseen costs;
- unanticipated reductions in the borrowing base under the credit agreement we are party to;
- our dependence on the availability, use and disposal of water in our drilling, completion, and production operations;
- significant competition for oil and natural gas acreage and acquisitions;
- environmental or other governmental regulations, including legislation related to hydraulic fracture stimulation and climate change measures;
- our ability to secure firm reliable transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;

- future environmental, social and governance ("ESG") ESG compliance developments and increased attention to such matters which could adversely affect our ability to raise equity and debt capital;

- management's ability to execute our plans to meet our optimal goals;

- the occurrence of cybersecurity incidents, attacks or other breaches to our information technology systems or on systems and infrastructure used by the oil and gas industry;

- future cyber risk compliance developments and its effect on the loss of confidentiality, integrity, or availability of information, data, or information (or control) systems that reflect the potential adverse impacts to organizational operations and assets, individuals, or other organizations;

- our ability to find and retain highly skilled personnel and our ability to retain key members of our management team on commercially reasonable terms;

- adverse weather conditions;

- actions or inaction of third-party operators of our properties;

- costs and liabilities associated with environmental, health, and safety laws;

- the effect of our oil and natural gas derivative activities;

- social unrest, political instability, or armed conflict in major oil and natural gas producing regions outside the United States, including evolving geopolitical and military hostilities in the Middle East, Russia and Ukraine and acts of terrorism or sabotage;

- impacts of world health events, including the coronavirus ("COVID-19"), and any reactive or proactive measures taken by businesses, governments and by other organizations related thereto, and the direct and indirect effects of world health events on the market for and price of oil and natural gas;

- our insurance coverage may not adequately cover all losses that may be sustained in connection with our business activities;

- possible adverse results from litigation and the use of financial resources to defend ourselves;

- and the other factors discussed in Part I, Item 1A-- "Risk Factors" in this Annual Report, as well as in our financial statements, related notes, and the other financial information appearing elsewhere in this Annual Report and our other reports filed from time to time with the Securities and Exchange Commission (the "SEC").

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date that such statements are made. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

Unless the context otherwise requires, references in this Annual Report to "Ring," "Ring Energy," the "Company," "we," "us," "our" or "ours" refer to Ring Energy, Inc.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and within this report.

Bbl – One barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Boe – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent. The ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas differs significantly from the price for a barrel of oil. A barrel of natural gas liquids also differs significantly in price from a barrel of oil.

Boepd – Boe per day.

Btu – British thermal unit, the quantity of heat required to raise the temperature of one pound of water by one-degree Fahrenheit.

Completion – The process of treating and hydraulically fracturing a drilled well followed by the installation of permanent equipment for the production of oil and natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate regulatory agency.

Developed acreage – The number of acres which are allotted or assignable to producing wells or wells capable of production.

Development activities – Activities following exploration including the drilling and completion of additional wells and the installation of production facilities.

Dry hole or ***well***– A well found to be incapable of producing hydrocarbons economically.

ESG – Environmental, Social and Governance.

Exploitation – A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploration – encompasses the processes and methods involved in locating potential sites for oil and natural gas drilling and extraction.

Field – An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

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

Held by Production or ***HBP***– A provision in an oil and gas property lease that extends a company's right to operate a property as long as the property produces a minimum amount of oil and/or gas.

Horizontal drilling – A drilling technique that permits the operator to drill horizontally within a specified targeted reservoir and thus exposes a larger portion of the producing horizon to a wellbore than would otherwise be exposed through conventional vertical drilling techniques.

Hydraulic fracturing or ***Fracking***– A well stimulation method by which fluid, comprised largely of water and proppant (purposely sized particles used to hold open an induced fracture) is injected downhole and into the producing formation at high pressures and rates in order to exceed the rock strength and create a fracture such that the proppant material can be placed into the fracture to enhance the productive capability of the formation.

Injection well – A well which is used to inject gas, water, or liquefied petroleum gas under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.

Joint Operating Agreement or***JOA*** – Any agreement between working interest owners concerning the duties and responsibilities of the operator and rights and obligations of the non-operators.

MBoe –One thousand barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

MMBoe –One million barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

MMBtu – One million Btu.

Mcf – One thousand cubic feet.

Natural gas liquidsor ***NGL*** – Natural gas liquids measured in barrels. Natural gas liquids are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics.

Net acres or***net wells***– The sum of the fractional working interests owned in gross acres or gross wells.

NYMEX – The New York Mercantile Exchange.

Overriding royalty interest or ***ORRI*** – An undivided interest in an oil, natural gas and mineral lease entitling the owner to a share of oil or natural gas production. The ORRI is carved out of the working interest or lease and cannot be fractionalized. It is an undivided, non-possessory right to a share of the production, excluding the mineral lease's drilling, production and operation costs.

Plugging and abandonment or***P&A***– Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface.

PV-10 – The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with the SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) non-property related expenses such as general and administrative expenses, debt service, and future income tax expense, and (ii) depreciation, depletion and amortization.

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

Proppant – A solid material, typically treated sand or man-made ceramic materials, designed to keep an induced hydraulic fracture open, during or following a fracturing treatment.

Proved developed nonproducing reserves or***PDNP***– Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending completion activities and the installation of surface equipment or gathering facilities or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved developed but nonproducing reserves.

Proved developed producing reserves or ***PDP***– Reserves that can be expected to be recovered from existing wells and completions with existing equipment and operating methods.

Proved developed reserves or***PD***– The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved reserves – Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain.

Proved undeveloped reserves or***PUD***– Proved 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.

Recompletion – The completion for production of an existing well bore in another formation from that in which the well has been previously completed.

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

Royalty interest – An interest in an oil and natural gas property entitling the royalty owner to a share of oil and/or natural gas production free of costs of production.

RRC – Texas Railroad Commission.

Shut-in reserves – Those reserves expected to be recovered from completion intervals that were open at the time the reserve was estimated but were not producing due to market conditions, mechanical difficulties, or because production equipment or pipelines were not yet installed. These reserves are included in the PDNP category in our reserve report.

SOFR – Secured Overnight Financing Rate.

Standardized Measure – The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.

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

Working interest or***WI***– The ownership interest, generally defined in a JOA, that gives the owner the right to drill, produce, and/or conduct operating activities on the leased property and share in the sale of production therefrom, subject to all royalties, overriding royalties, and other lease burdens. In addition, the owner of the working interest must share in all costs of exploration, development operations and all risks in connection therewith.

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

WTI – West Texas Intermediate light sweet crude oil, a benchmark in crude oil pricing.

PART I

Item 1: Business

General

Ring Energy, Inc., a Nevada corporation ("Ring," "Ring Energy," the "Company," "we," "us," "our," or similar terms), is a growth oriented independent oil and natural gas exploration and production company based in The Woodlands, Texas and is engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas. Our primary drilling operations target the oil and liquids rich producing formations in the Northwest Shelf and the Central Basin Platform, and the Delaware Basin all of which are part of in the Permian Basin in Texas.

As of December 31, 2022 December 31, 2023, our leasehold acreage positions totaled 124,217 96,127 gross (102,175 (80,535 net) acres and we held interests in 1,056 1,043 gross (888 (864 net) producing wells. Proved reserves as of December 31, 2022 December 31, 2023 (based upon the report of our independent petroleum engineer of that date) were approximately 138.1 million 129.8 million Boe, (barrel of oil equivalent), of which we are the operator of approximately 98%. All of our properties are located in the Permian Basin. Our Basin and our proved reserves are oil-weighted, with approximately 64% 63% consisting of oil, 19% consisting of natural gas, and 17% 18% consisting of natural gas liquids. Of those NGLs. Approximately 68% of the reserves approximately 65% are classified as proved developed or "PD" PD and 35% 32% are classified as proved undeveloped, or "PUD." PUD. Within the "PD" PD reserve category, 235 re-completion 242 recompletion and re-activation opportunities are classified as proved developed not producing "PDNP" PDNP and within the "PUD" PUD reserve category, we have a total of 214 211 proved locations (43% (33% horizontal and 57% 67% vertical) based on the reserve report as of December 31, 2022.We December 31, 2023. We believe our core leasehold in the Northwest Shelf and Central Basin Platform contain additional potential drilling locations. For the calculation of Boe, a barrel of oil is weighted on a 6 to 1 ratio to one thousand cubic feet ("Mcf") of natural gas.

2022 2023 Highlights and Major Developments

- Amended our revolving credit facility "RBL" with an initial borrowing base of $600.0 million
- Closed the Stronghold Founders Acquisition on August 31, 2022
- Increased liquidity position at year-end 2022 to approximately $188.0 million which was a 205% increase versus year-end 2021 of $61.6 million
- Improved RBL available balance at year-end 2022 to $184.2 million or 31% of undrawn capacity on the RBL versus year-end 2021 of $59.2 million or 17% of undrawn capacity August 15, 2023
- Achieved record full year production of 12,364 18,119 Boepd (77% Oil) (69% oil), a year-over-year increase of 45% 47%
- Executed a continuous phased drilling program in 2022 which 2023 that included drilling 32.00 31.00 gross / 31.35 29.75 net operated wells consisting of 27.00 gross 20.00 horizontal wells and 5.00 gross 11.00 vertical wells (gross). In addition, the Company participated in 5.00 non-operated wells.
- Increased total Maintained our revolving credit facility borrowing base of $600 million
- Total Proved Reserves to 138.1 were 129.8 MMBoe at year-end 2022, a year-over-year increase of 78% 2023

Our Mission

Ring's mission is to deliver competitive and sustainable returns to its shareholders by developing, acquiring, exploring for, and commercializing oil and natural gas resources it believes that are vital to the world's health and welfare.

Our Key Principles

Successfully achieving Ring's mission requires a firm commitment to operating safely in a socially responsible and environmentally friendly manner. Key principles supporting Ring's strategic vision are to:

- ensure health, safety, and environmental excellence, and a strong commitment to Ring's employees and the communities in which we work and operate;
- continue our focus on generating adjusted free cash flow to improve and build a sustainable financial foundation;
- pursue rigorous capital discipline focused on Ring's highest returning opportunities;
- improve margins and drive value by targeting additional operating cost reductions and capital efficiencies; and
- strengthen our balance sheet by steadily paying down debt, divesting of non-core assets and becoming a peer leader in Debt/EBITDA metrics.

Our Business Strategy

Our business strategy is guided by the above key principles and implemented by pursuing the following five strategic objectives, which are foundational aspects of our culture and success.

Attract and retain highly qualified people - Achieving our mission is only possible through our employees. It is critical to have compensation, development, and human resource programs that attract, retain, and motivate the people we need to succeed.

Pursue operational excellence with a sense of urgency - We seek to deliver low cost, consistent, timely, and efficient execution of our drilling campaigns, work programs, and operations. We execute our operations in a safe and environmentally responsible manner, focus on reducing our emissions, apply advanced technologies, and continuously seek ways to reduce our operating cash costs on a per barrel basis.

Invest in high-margin, high rate-of-return projects - We prioritize our work programs and allocate capital to the highest return opportunities in our inventory on an ongoing basis. This objective is key to profitably growing our production and reserve levels and generating the excess cash from operations.

Focus on generating adjusted free cash flow **and** ***strengthen strengthening our balance sheet*** - We seek to continuously reduce long-term debt using excess cash from operations and potentially through the sale of non-core assets. Continuing to generate adjusted free cash flow through a disciplined capital allocation program and reducing our operating and corporate costs are key components of this objective. Our capital program is funded by operational cash flow and limited seeks to balance our production and reserve growth versus with paying down debt. We believe that remaining focused and disciplined in this regard will lead to meaningful returns for our shareholders and provide additional financial flexibility to manage potential future swings in business cycles. Our commodity hedges are designed to help ensure the necessary cash flow to adhere to these plans while retaining the flexibility to participate in prevailing commodity markets.

Pursue strategic acquisitions that maintain or reduce our break-even costs - We actively pursue accretive acquisitions, mergers, and property dispositions in seeking to improve our margins, returns, and break-even costs. Financial strategies associated with these efforts will focus on delivering competitive debt-adjusted per share returns. This objective is key to delivering competitive returns to our shareholders on a sustainable basis.

Stronghold Founders Acquisition

On July 1, 2022 August 15, 2023, Ring the Company, as buyer, and Stronghold Energy II Operating, Founders Oil & Gas IV, LLC a Delaware limited liability company ("Stronghold OpCo") and Stronghold Energy II Royalties, LP, a Delaware limited partnership ("Stronghold RoyaltyCo", together with Stronghold OpCo, collectively, "Stronghold" Founders"), entered into a purchase and sale agreement as seller, closed the Asset Purchase Agreement (the "Purchase Agreement" "Founders Purchase Agreement"), under which Ring the Company acquired (the "Stronghold "Founders Acquisition") interests in oil and gas leases and related property of Stronghold consisting of approximately 37,000 net acres Founders in the Central Basin Platform of the Texas Permian Basin. On August 31, 2022, we completed Basin in Ector County, Texas.

Common Warrants Exercised

During 2023, the Stronghold Acquisition.

Upon closing Company reduced its dilutive shares through the exercise of 19,029,593 of the Stronghold Acquisition, Stronghold exercised its right Company's outstanding common warrants, bringing the total outstanding to designate two directors 78,200 common warrants as of December 31, 2023. This was accomplished by the exercise of 4,517,427 common warrants at an exercise price of $0.80 per share and the exercise of 14,512,166 common warrants at an exercise price of $0.62 per share, through amendments to our Board certain warrant agreements. These exercises resulted in $12,301,596 of Directors (the "Board"). On September 1, 2022, Roy I. Ben-Dor and David S. Habachy were appointed net proceeds to the Board. Company after payment of $309,888 in advisory fees.

Primary Business Operations

We seek to rigorously manage our asset portfolio to optimize shareholder value over the long term.

In the first quarter of 2022, we contracted 2023, in the Northwest Shelf, the Company drilled and completed two 1-mile horizontal wells (each with a rig for our working interest of 100%), and two 1.5-mile horizontal drilling program wells (one with a working interest of approximately 99.8% and began operations on January 31st. We the other with a working interest of approximately 75.4%). Next, in its Crane County acreage within the Central Basin Platform, the Company drilled and completed three 1-mile horizontal vertical wells and one 1.5-mile horizontal well in the Central Basin Platform. We then moved the rig to the Northwest Shelf and drilled two 1-mile horizontal wells. All wells drilled in the first quarter had (each with a working interest of 100%) and performed six vertical well recompletions (each with a working interest of 100%).

In the second quarter of 2022, we drilled a total of nine wells, completed seven wells, and began the completion process on four wells, all 2023, in the Northwest Shelf. The first Shelf, the Company drilled and completed two 1.5-mile horizontal wells completed were (one with a working interest of 100% and the other with a working interest of approximately 75.4%) and two 1-mile horizontal wells which were (both with a working interest of approximately 91.1%). Additionally, in its Crane County acreage within the Central Basin Platform, the Company drilled in and completed two vertical wells (each with a working interest of 100%) and performed three vertical well recompletions (each with a working interest of 100%).

During the first quarter. Next, we third quarter of 2023, the Company drilled and completed two 1-mile horizontal wells (one with a working interest of 100%, two 1.5-mile horizontal wells and the other with a working interest of approximately 98.7% 75%) in the Northwest Shelf, and one 1-mile three 1.5-mile horizontal well wells (each with a working interest of approximately 75.4%. We also drilled and began the completion process on an additional four 1-mile horizontal wells. Two of the wells have a working interest of 100%, one has a working interest of approximately 87.9%, and the fourth has a working interest of 75%.

In the third quarter of 2022, we completed and placed on production the four aforementioned 1-mile horizontal wells in the Northwest Shelf, which were drilled in the second quarter. Next, we drilled and completed two 1.5-mile horizontal wells and one 1-mile horizontal well) in the Central Basin Platform. Additionally, in its Crane County acreage within the Central Basin Platform, the Company drilled and two 1-mile horizontal completed three vertical wells in the Northwest Shelf, each (each with a working interest of 100%). During Lastly, the last month of the quarter, we Company drilled and began the completion process on three 1-mile horizontal wells in the Northwest Shelf two (each with a working interest of 99.7% and one with a working interest of 100%). In total, during the third quarter of 2022, we drilled eight, completed nine, and began the completion process on three horizontal wells. With the addition of the Stronghold Acquisition assets in the Central Basin Platform, we also performed three vertical well re-completions.

In the fourth quarter of 2022, we 2023, the Company completed and placed on production the three aforementioned 1-mile horizontal wells in the Northwest Shelf. Next, we Additionally, the Company drilled and completed one saltwater disposal (SWD) well in the Northwest Shelf (with a working interest of 100%), and completed the 2023 horizontal drilling program with one 1.5-mile horizontal well in the Northwest Shelf (with a working interest of approximately 97.7%), as well as two 1-mile horizontal wells and one 1.5-mile horizontal well (each with a working interest of 100%, also in the Northwest Shelf. To complete the 2022 horizontal drilling program, we drilled and completed two 1.5-mile horizontal wells) in the Central Basin Platform. In addition to the horizontal wells, we performed nine more vertical well re-completions and drilled and completed five new vertical wells on the Stronghold Acquisition assets located in its Crane County Texas, of acreage within the Central Basin Platform, all the Company drilled and completed three vertical wells (each with a working interest of 100%).

In summary, for 2022, we 2023, the Company drilled and completed 27 20 horizontal wells, and 5 11 vertical wells, along with 12 and 1 SWD well. In addition, the Company performed 9 vertical well re-completions on the Stronghold Acquisition assets. recompletions. The table below sets forth our drilling and completion activities for 2022 2023 by quarter, and full year total through December 31, 2022 December 31, 2023.

Quarter	Area	Wells Drilled	Wells Completed	Recompletions
1Q 2022	Central Basin Platform (Horizontal)	4	4	—
	Central Basin Platform (Vertical)	—	—	—
	Northwest Shelf	2	—	—
2Q 2022	Central Basin Platform (Horizontal)	—	—	—
	Central Basin Platform (Vertical)	—	—	—
	Northwest Shelf	9	7	—
3Q 2022	Central Basin Platform (Horizontal)	3	3	—
	Central Basin Platform (Vertical)	—	—	3
	Northwest Shelf	5	6	—
4Q 2022	Central Basin Platform (Horizontal)	2	2	—
	Central Basin Platform (Vertical)	5	5	9
	Northwest Shelf	2	5	—

Quarter	Area	Wells Drilled	Wells Completed	Recompletions
1Q 2023	Northwest Shelf (Horizontal)	4	4	—
	Central Basin Platform (Horizontal)	—	—	—
	Central Basin Platform (Vertical)	3	3	6
	Total	7	7	6
2Q 2023	Northwest Shelf (Horizontal)	4	4	—
	Central Basin Platform (Horizontal)	—	—	—
	Central Basin Platform (Vertical)	2	2	3
	Total	6	6	3
3Q 2023	Northwest Shelf (Horizontal)	5	2	—
	Central Basin Platform (Horizontal)	3	3	—
	Central Basin Platform (Vertical)	3	3	—
	Total	11	8	—
4Q 2023	Northwest Shelf (Horizontal)	1	4	—
	Central Basin Platform (Horizontal)	3	3	—
	Central Basin Platform (Vertical)	3	3	—
	Total (1)	7	10	—

FY 2023	Northwest Shelf (Horizontal)	14	14	—
	Central Basin Platform (Horizontal)	6	6	—
	Central Basin Platform (Vertical)	11	11	9
	Total (1)	31	31	9

(1) Fourth quarter total and full year total do not include one SWD well completed in the Northwest Shelf.

Ring Energy's Strengths

Our strengths include:

- high quality asset base in one of North America's leading oil and gas producing regions characterized by relatively low declines and attractive margins;
- de-risked Permian Basin acreage position with multi-year drilling inventory of horizontal and vertical development potential;
- concentrated acreage position with high degree of operational control;
- experienced and proven management team with substantive technical and operational expertise;
- operating control over most of our production and development activities; and
- commitment to cost efficient operations, health, safety, protecting the environment, our employees, and the communities in which we work and operate.

Competitive Business Conditions

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

Marketing, Pricing, and Transportation

The actual price range of crude oil is largely established by major crude oil purchasers and commodities trading. Pricing for natural gas is based on regional supply and demand conditions. To this extent, we believe we receive oil and natural gas prices comparable to other producers in our areas of operation. We believe there is little risk in our ability to sell our production at prevailing prices. We view potential declines in oil and gas prices to a level which could render our current production uneconomical as our primary pricing risk.

We are presently committed to use the services of the existing gathering systems of the companies that purchase our natural gas production. This commitment is tied to existing natural gas purchase contracts associated with our production, which potentially gives such gathering companies certain short-term relative monopolistic powers to set gathering and transportation costs. Obtaining the services of an alternative gathering company is not currently realistic as it would require substantial additional costs (since an alternative gathering company would be required to lay new pipeline and/or obtain new rights of way to any lease from which we are selling production).

We are not subject to third-party gathering systems with respect to our oil production. Some of our oil production is sold through a third-party pipeline pipelines which has have no regional competition and all other oil production is transported by the oil purchaser by trucks with competitive trucking costs in the area.

Our oil is transported from the wellhead to tank batteries or delivery points through our flow-lines or gathering systems. Purchasers of our oil take delivery (i) at a pipeline delivery point or (ii) at our tank batteries for transport by truck. Our natural gas is transported from the wellhead to the purchaser's meter and pipeline interconnection point through our gathering systems. We have implemented a Leak Detection and Repair program, or LDAR, to locate and repair leaking components including valves, pumps and connectors, in order to minimize the emission of fugitive volatile organic compounds and hazardous air pollutants. In addition, as an ongoing practice, we install vapor recovery units in our newly installed tank batteries which also reduces emissions. Our produced salt water saltwater is generally moved by pipeline connected to our operated salt water saltwater disposal wells or by pipeline to commercial disposal facilities.

Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is trucked to storage facilities.

For the year ended December 31, 2022 December 31, 2023, sales to three customers, Phillips 66 Company ("Phillips"), Enterprise Crude Oil LLC ("Enterprise"), and NGL Crude Partners ("NGL Crude"), and Enterprise Crude Oil LLC ("Enterprise") represented 68% 66%, 13% 12%, and 5% 10%, respectively, of our oil, natural gas, and natural gas liquids revenues. As of December 31, 2022 December 31, 2023, Phillips represented 69% 65% of our accounts receivable, NGL Crude Enterprise represented 7% 11% of our accounts receivable and Enterprise NGL Crude represented 10% 8% of our accounts receivable. We believe that the loss of any of these customers purchasers would not materially impact our business because we could readily find other purchasers for our oil and natural gas.

Delivery Commitments

As of December 31, 2022 December 31, 2023, we were not committed to providing a fixed quantity of oil or natural gas under any existing contracts.

Commodity Hedging

We have an active commodity hedging program through which we seek to hedge a meaningful portion of our expected oil and gas production, thereby reducing our exposure to downside commodity prices and enabling us to protect cash flows to meet our debt obligations under our credit facility and secondarily to maintain liquidity to fund our capital expenditures needs.

Governmental Regulations

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, can affect our profitability.

Regulation of Drilling and Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state, and local statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. The trend in oil and natural gas regulation has been to increase regulatory restrictions and limitations on such activities. Any changes in, or more stringent enforcement of, these laws and regulations may result in delays or restrictions in permitting or development of projects or more stringent or costly construction, drilling, water management or completion activities or waste handling, storage, transport, remediation, or disposal emission or discharge requirements which could have a material adverse effect on the Company. For example, in January 2021, President Biden signed an Executive Order directing the Department of Interior (the "DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed, although litigation over the leasing pause remains ongoing. In February 2022, another judge ruled that the Biden Administration's efforts to raise the cost of climate change in its environmental assessments, would increase energy costs and damage state revenues from energy production. This ruling has caused federal agencies to delay issuing new oil and gas leases and permits on federal lands and waters. While we do not have a significant federal lands acreage position (240 net acres as of December 31, 2022), these actions could have a material adverse effect on our industry and the Company.

Currently, all of our operated properties and operations are in Texas, and New Mexico, which have has regulations governing conservation matters, such as the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, both Texas and New Mexico impose imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids NGLs within their its jurisdictions.

The failure to comply with these rules and regulations 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 of Transportation of Oil

Sales of crude oil, condensate, and natural gas liquids NGLs are not currently regulated and are made at negotiated prices, prices; however, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms, and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, ("FERC"), regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors. Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

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

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors.

Environmental Compliance and Risks

Our oil and natural gas exploration, development, and production operations are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. At the federal level, among the more significant laws that may affect our business and the oil and natural gas industry generally are: the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"); the Oil Pollution Act of 1990 ("OPA"); the Resource Conservation and Recovery Act ("RCRA"); the Clean Air Act ("CAA"); Federal Water Pollution Control Act of 1972, or the Clean Water Act ("CWA"); and the Safe Drinking Water Act of 1974 ("SDWA"). These federal laws are administered by the United States Environmental Protection Agency ("EPA"). Generally, these laws (i) regulate air and water quality, impose limitations on the discharge of pollutants and establish standards for the handling of solid and hazardous wastes; (ii) subject our operations to certain permitting and registration requirements; (iii) require remedial measures to mitigate pollution from former or ongoing operations; and (iv) may result in the assessment of administrative, civil and criminal penalties for failure to comply with such laws. In addition, there is environmental regulation of oil and gas production by state and local governments in the jurisdictions where we operate. As described below, there are various regulations issued by the EPA and other governmental agencies pursuant to these federal statutes that govern our operations.

In Texas, and New Mexico, specific oil and natural gas regulations apply to oil and natural gas operations, including the drilling, completion and operations of wells, and the disposal of waste oil and saltwater. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency.

At the federal level, among the more significant laws and regulations that may affect our business and the oil and natural gas industry are:

Hazardous Substances and Wastes

CERCLA, also known as the Superfund law, and analogous state laws impose liability on certain classes of persons, known as "potentially responsible parties," for the disposal or release of a regulated hazardous substance into the environment. These potentially responsible parties include (1) the current owners and operators of a facility, (2) the past owners and operators of a facility at the time the disposal or release of a hazardous substance occurred, (3) parties that arranged for the offsite disposal or treatment of a hazardous substance, and (4) transporters of hazardous substances to off-site disposal or treatment facilities. While petroleum and natural gas liquids NGLs are not designated as a "hazardous substance" under CERCLA, other chemicals used in or generated by our operations may be regulated as hazardous substances. Potentially

responsible parties under CERCLA may be subject to strict, joint and several liability for the costs of investigating and cleaning up environmental contamination, for damages to natural resources and for the costs of certain health studies. In addition to statutory liability under CERCLA, common law claims for personal injury or property damage can also be brought by neighboring landowners and other third parties related to contaminated sites.

RCRA, and comparable state statutes and their implementing regulations, regulate the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and solid (non-hazardous) wastes. Under a delegation of authority from the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Federal and state regulatory agencies can seek to impose administrative, civil, and criminal penalties for alleged non-compliance with RCRA and analogous state requirements. Certain wastes associated with the production of oil and natural gas, as well as certain types of petroleum-contaminated media and debris, are excluded from regulation as hazardous waste under Subtitle C of RCRA. These wastes, instead, are regulated as solid waste (i.e. non-hazardous waste) under the less stringent provisions of Subtitle D of RCRA. It is possible, however, that certain wastes now classified as non-hazardous could be classified as hazardous wastes in the future and therefore be subject to more rigorous and costly disposal requirements. Legislation has been proposed from time to time in Congress to regulate certain oil and natural gas wastes as hazardous waste under RCRA. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Under CERCLA, RCRA and analogous state laws, we could be required to remove or remediate environmental impacts on properties we currently own and lease or formerly owned or leased (including hazardous substances or wastes disposed of or released by prior owners or operators), to clean up contaminated off-site disposal facilities where our wastes have come to be located or to implement remedial measures to prevent or mitigate future contamination. Compliance with these laws may constitute a significant cost and effort for us. No specific accounting for environmental compliance has been maintained or projected by us at this time. We are not presently aware of any material environmental demands, claims, or adverse actions, litigation or administrative proceedings in which either we or our acquired properties are involved in or subject to, or arising out of any predecessor operations.

Air Emissions

Our operations are subject to the CAA and comparable state and local laws and regulations, which regulate emissions of air pollutants from various sources and mandate certain permitting, monitoring, recordkeeping, and reporting requirements. The CAA and its implementing regulations may require that we obtain permits prior to the construction, modification, or operation of certain projects or facilities expected to produce or increase air emissions above certain threshold levels and strictly comply with those permits, including emissions and operational limitations. These permits may require us to install emission control technologies to limit emissions, which can impose significant costs on our business.

In 2012 and 2016, November 2021, the EPA issued a proposed rule under the CAA's New Source Performance Standards, known as Subpart OOOOa, intended to regulate reduce methane emissions of sources of volatile organic compounds ("VOCs"), sulfur dioxide, air toxics and methane from various oil and natural gas exploration, production, processing and transportation facilities. On May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified, and existing oil and gas facilities. Given the long-term trend toward increasing regulation, future federal Greenhouse Gas ("GHG") regulations of the oil and gas industry remain a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities. In November 2021, the EPA proposed new source performance standards and emissions guidelines to reduce methane and other pollution from new and existing sources in the oil and gas industry. sources. The proposed rule would include, among other things, make the existing regulations in Subpart OOOOa more stringent and create a comprehensive monitoring program Subpart OOOOb to expand reduction requirements for new, modified, and existing well sites, zero-emissions reconstructed oil and gas sources, including standards for new and existing focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controls, and standards to eliminate venting of controllers, associated gas, and requirements for liquids unloading facilities). In addition, the capture and sale of natural gas where proposed rule would establish "Emissions Guidelines," creating a sales line is available. If adopted, these requirements could increase our costs Subpart OOOOc that would require states to operate and control pollution. develop plans to reduce methane emissions from existing sources that must be at least as effective as presumptive standards set by the EPA. In November 2022, the EPA issued a Supplemental Proposal regarding the proposed new source performance standards and emissions guidelines for reducing methane and VOCs in the oil and natural gas sector. The Supplemental Proposal expands rule supplementing the November 2021 proposal to include more comprehensive requirements to reduce proposed rule. Among other things, the November 2022 supplemental proposed rule removes an emissions including application of methane monitoring obligations to exemption for small wellhead-only sites and well sites with low emissions. It also would create creates a new third-party monitoring program to flag large emissions events, known referred to in the proposed rule as "super emitters." In December 2023, the "Super-Emitter Response Program." EPA announced a final rule, which, among other things, requires the phase out of routine flaring of natural gas from newly constructed wells (with some exceptions) and routine leak monitoring at all well sites and compressor stations. Notably, the EPA updated the applicability date for Subparts OOOOb and OOOOc to December 6, 2022, meaning that sources constructed prior to that date will be considered existing sources with later compliance deadlines under state plans. The EPA expects final rule gives states two years to finalize its develop and submit their plans for reducing methane emissions from existing sources. The final emissions guidelines under Subpart OOOOc provide three years from the plan submission deadline for existing sources to comply. Compliance with these or any new methane rules regulations could result in 2023. The foregoing laws, regulations, and standards, as well as any future laws and their implementing regulations, may require us stricter permitting requirements, which in turn could delay or impair our ability to obtain pre-approval air emission permits and could result in increased expenditures for pollution control equipment, the expansion or modification costs of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. Until these rules are formally adopted, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. which could be significant.

On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 ("IRA"). The IRA allocated $1.55 billion to the Methane Emissions and Waste Reduction Incentive Program. The IRA also required the EPA to implement a waste emission charge on methane emitted from applicable oil and gas facilities that exceed certain thresholds. The methane charge goes into effect in 2024 at $900 per metric ton of methane and increases to $1,500 per metric ton of methane by 2026. The On January 12, 2024, the EPA announced a proposed rule to implement the methane emissions charge.The charge will act as an incentive for operators to reduce emissions by minimizing leaks and replacing equipment rather than paying for excessive emissions.

In November 2022, the Department of the Interior announced a proposed rule from the Bureau of Land Management ("BLM") that would impose additional requirements on oil and natural gas production on federal and Tribal lands, including the use of "low bleed" pneumatic equipment and vapor recovery for oil storage tanks, implementation of leak detection plans, implementation of waste minimization plans, and monthly limits on royalty-free flaring. If adopted, these rules could affect our adversely affect our production of oil and gas pursuant to federal leases in New Mexico.

In October 2015, the EPA announced that it was lowering the primary National Ambient Air Quality Standards ("NAAQS") for ozone from 75 parts per billion to 70 parts per billion. Since that time, the EPA has issued area designations with respect to ground-level ozone. In December 2020, the EPA announced its intention to leave the ozone NAAQS unchanged at 70 parts per billion rather than lower them further. However, as discussed above, that action could be subject to reversal following the Biden Administration's January 2021 executive order. In mid-2022, the Biden Administration announced that it was considering designating the Permian Basin in Texas as a "non-attainment zone," which, if designated, would result in increased permitting and compliance requirements for drilling operations in the state to decrease ozone levels. The Biden Administration has since omitted the potential designation from an agenda of planned regulations, indicating that it is not expected to be finalized in the next year. The EPA, however, could revive the effort in the future. In 2022, the New Mexico Environment Department ("NMED") adopted "ozone precursor rules." The ozone precursor rules went into effect on August 5, 2022 and apply to oil and gas sources in New Mexico that would cause or contribute to ambient ozone concentrations that exceed 95% of the NAAQs for ozone. As of the effective date, these rules apply to oil and natural gas production in the following counties in New Mexico: Chaves, Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia. The rules apply to certain crude oil and natural gas production and processing equipment associated with operations. Reclassification of areas of state implementation of NAAQS, or designation of areas in which we operate as non-attainment zones, 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.

Moreover, the NMOCD recently adopted new rules, which require oil and gas operators to capture 98 percent of their methane waste by the end of 2026. The new rules went into effect on May 25, 2021. While the State of Texas has not formally conducted a recent rulemaking related to air emissions, scrutiny of oil and natural gas operations and the rules affecting them have increased in recent years. For example, the EPA and environmental non-governmental organizations have conducted flyovers with optical gas imaging cameras to survey emissions from oil and natural gas production facilities and transmission infrastructure. In August 2022, for example, the EPA announced that it would be conducting helicopter flyovers of the Permian Basin region in New Mexico and Texas. The flyovers used infrared cameras to survey oil and gas operations to identify large emitters of methane and VOCs. volatile organic compounds ("VOCs"). Based on data obtained during flyovers, EPA intends to initiate enforcement follow up actions with facilities operators. In addition, the RRC has increased oversight related to flaring, with reporting reviews and site inspections. While none of these activities increases our compliance obligations, they signal the potential for increased enforcement and possible rulemaking in the future.

Oil Pollution Prevention

The OPA amended the CWA to impose liability for releases of crude oil from vessels or facilities into navigable waters. If a release of crude oil into navigable waters occurs during shipment or from an oil terminal, we could be subject to liability under the OPA. In 1973, the EPA adopted oil pollution prevention regulations under the CWA. These oil pollution prevention regulations require the preparation of a Spill Prevention Control and Countermeasure ("SPCC") plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming crude oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. SPCC requirements under the CWA require appropriate containment berms and similar structures to help prevent the discharge of pollutants into regulated waters in the event of a crude oil or other constituent tank spill, rupture, or leak. The SPCC regulations require affected facilities to prepare a written, site-specific SPCC plan, which details how a facility's operations comply with the requirements of the pollution prevention regulations. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intra-facility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. Where applicable, we maintain and implement SPCC plans for our facilities.

Water Discharges

The CWA and analogous state laws and regulations impose restrictions and strict controls regarding the discharge of pollutants into navigable waters, defined as waters of the United States ("WOTUS"), as well as state waters. The CWA prohibits the placement of dredge or fill material in wetlands or other WOTUS unless authorized by a permit issued by the U.S. Army Corps of Engineers ("Corps") or a delegated state agency pursuant to Section 404. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Also, in June 2016, the EPA issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and natural gas extraction facilities from sending wastewater to publicly owned treatment works. This restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs. 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.

In January2023, January 2023, the EPA and the Corps issued a final rule that revises the definition of WOTUS. The Separately, in May 2023, the U.S. Supreme Court's decision in Sackett v. EPA narrowed federal jurisdiction over wetlands to "traditional navigable waters" and wetlands or other waters that have a "continuous surface connection" with or are otherwise indistinguishable from traditional navigable water. In September 2023, the EPA and the Corps published a direct-to-final rule that conforms the regulatory definition of "Waters of the United States" to the Supreme Court's May 2023 decision in Sackett. However, litigation opposing the September 2023 final rule has been challenged by several states remains ongoing and industry groups. As a result substantial uncertainty exists with respect to future implementation of these developments, the September 2023 rule and the scope of federal CWA jurisdiction under more generally. To the CWA is uncertain at this time. The pending litigation and extent the rule or any future regulations concerning the definition of WOTUS may result in an expansion of rule or court decision expands the scope of the CWA's jurisdiction, and we could face increased permitting costs and delays with respect to obtaining permits for dredge and fill activities in WOTUS in connection with our operations. project delays.

Underground Injection Control

The underground injection of crude oil and natural gas wastes is regulated by the Underground Injection Control ("UIC") program, as authorized by the SDWA, as well as by state programs. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluid from the injection zone into underground sources of drinking water, as well as to prevent communication between injected fluids and zones capable of producing hydrocarbons. The SDWA establishes requirements for permitting, testing, monitoring, recordkeeping, and reporting of injection well activities, as well as a prohibition against the migration of fluid containing contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in the suspension of permits, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injuries.

Under the auspices of the federal UIC program as implemented by states with UIC primacy, regulators, particularly at the state level, are becoming increasingly sensitive to possible correlations between underground injection and seismic activity. Consequently, state regulators implementing both the federal UIC program and state corollaries are heavily scrutinizing the location of injection facilities relative to faulting and are limiting both the density and injection facilities as well as the rate of injection.

In New Mexico, the New Mexico Oil Conservation Division ("NMOCD") administers the UIC program for all injection wells that are related to oil and natural gas production. In Texas, the Texas Railroad Commission ("RRC") RRC regulates the disposal of produced water by injection well. Permits must be obtained before drilling saltwater disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water saltwater to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. 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. In 2021, the NMOCD announced a new plan for responding to increased seismic activity in the Permian Basin. Under the new plan, pending permits for wastewater injection in certain areas will be subject to additional reporting and monitoring requirements. 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 produced 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. In addition, third-party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

Hydraulic fracturing is a practice in the oil and natural gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations by injecting water, sand, and chemicals under pressure. Oil and natural gas may be recovered from certain of our oil and natural gas properties through the use of hydraulic fracturing. Hydraulic fracturing is subject to regulation by state regulatory authorities, and several federal agencies have asserted federal regulatory authority over certain aspects of the hydraulic fracturing process. For example, the EPA published permitting guidance in February 2014 addressing the use of diesel fuel in fracturing operations, and in June 2016 EPA issued final effluent limitations guidelines under the CWA that waste-water from shale natural gas extraction operations must meet before discharging to a publicly owned treatment works. Separately, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands. However, a Wyoming federal court struck down this rule in June 2016. The June 2016 decision was appealed by the BLM to the U.S. Circuit Court of Appeals for the Tenth Circuit. However, following issuance of a presidential executive order to review rules related to the energy industry, in July 2017, the BLM published a notice of proposed rulemaking to rescind the 2015 final rule. In September 2017, the Tenth Circuit issued a ruling to vacate the Wyoming trial court decision and dismiss the lawsuit challenging the 2015 rule in light of the BLM's proposed rulemaking. The BLM issued a final rule repealing the 2015 hydraulic fracturing rule in December 2017. The current administration has announced that it intends to review the repeal of the 2015 hydraulic fracturing rule under the *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process but, at this time, federal legislation related to hydraulic fracturing appears uncertain. In Texas, and New Mexico, specific oil and natural gas regulations apply to oil and gas operations, including the drilling, completion and operations of wells, and the disposal of waste oil and salt water. In October 2023, the RRC announced draft amendments to its water protection rules to, among other things, encourage waste recycling. There are also procedures incident to the plugging and abandonment of dry holes or other non-operational wells, all as governed by the applicable governing state agency. As an example, the RRC adopted rules in 2014 requiring companies seeking permits for disposal wells to provide seismic activity data in permit applications. The rules also allow the RRC to modify,

suspend, or terminate permits if a disposal well is determined to be causing seismic activity. Determinations by the RRC under these rules may adversely affect our operations. In New Mexico, the Produced Water Act, effective July 1, 2019, governs the discharge, handling, transport, storage, and recycling or treatment of produced water.

Additionally, New Mexico has adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. In January 2021, State Senator Antoinette Sedillo Lopez of New Mexico, introduced a bill which would prohibit certain uses of fresh water in fracking operations, require the disclosure of the chemical composition of produced water from spills, and increase penalties for produced water spills by the oil and gas industry. State Senator Sedillo introduced another bill for the 2021 legislative session seeking to prevent the New Mexico Energy, Minerals and Natural Resources Department from issuing new fracking permits until 2025. Similar legislation was unsuccessful in the 2019 and 2020 legislative sessions. However, if enacted, this legislation would have a material adverse effect on our business and prospects.

Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. In Texas, however, local governments are expressly preempted from regulating oil and gas operations with limited exceptions, under Texas Natural Resources Code Section 81.0523. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the local, state, or federal level, our fracturing activities could become subject to additional permit and financial assurance requirements, more stringent construction requirements, increased reporting or plugging and abandoning requirements or operational restrictions and associated permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable and could cause us to incur substantial compliance costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Climate Change

Continuing political and social attention to the issue of global climate change has resulted in both existing and pending international agreements and national, regional or local legislation and regulatory measures to limit or reduce emissions of so-called greenhouse gases ("GHGs"), such as cap and trade regimes, carbon taxes, restrictive permitting, increased fuel efficiency standards and incentives or mandates for renewable energy. In December 2009, the EPA published an endangerment finding concluding that emissions of CO_2, methane and certain other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the The EPA has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit requirements for GHG emissions from certain large stationary sources that already are major sources of criteria pollutants under the CAA. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In addition, the EPA has adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities on an annual basis, as well as reporting GHG emissions from gathering and boosting systems, oil well completions and workovers using hydraulic fracturing.

In June 2016, the EPA finalized rules to reduce methane emissions from new, modified or reconstructed sources in the oil and natural gas sector, including implementation of a leak detection and repair ("LDAR") program to minimize methane emissions, under the CAA's New Source Performance Standards in 40 C.F.R. Part 60, Subpart OOOOa ("GHG NSPS"). On April 18, 2017, the EPA announced its intention to reconsider certain aspects of those regulations, and in June 2017, the EPA proposed a two-year stay of certain requirements of the GHG NSPS regulations. In October 2018, the EPA proposed revisions to the GHG NSPS, such as changes to the frequency for monitoring fugitive emissions at well sites and changes to requirements that a professional engineer certify when meeting certain GHG NSPS requirements is technically infeasible. EPA proposed further revisions to the GHG NSPS on September 24, 2019, including rescinding the methane requirements in the GHG NSPS that apply to sources in the production and processing segments of the industry. In September 2020, the EPA finalized amendments to the GHG NSPS that rescind requirements for the transmission and storage segment of the oil and natural gas industry and rescind methane-specific limits that apply to the industry's production and processing segments, among other things. The current administration has announced that it intends to review the September 2020 rules under the *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis*, which review may result in the reinstatement of the now-rescinded standards or promulgation of more stringent standards. Our Company has taken measures to control methane leaks, but it is possible that these rules and future revisions thereto will require us to take further methane emission reduction measures, which may require us to expend material sums.

In addition, in November 2016, the BLM issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and natural gas operations on federal lands that are substantially similar to the CAA's New Source Performance Standards in 40 C.F.R. Part 60, Subpart OOOOa ("GHG NSPS NSPS") requirements. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in In September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule, which became effective on November 27, 2018. Both the 2016 and the 2018 rule were challenged in federal court. On July 21, 2020, a Wyoming federal court vacated almost all resulting in the rescission of both rules. Appeals to those decisions are ongoing, but with little activity in the 2016 rule, including all provisions relating to the loss of gas through venting, flaring, and leaks, and on July 15, 2020, a California federal court vacated the 2018 rule. As a result of these decisions, the 1979 regulations concerning venting, flaring and lost production on federal land have been reinstated. The current administration is likely to impose new regulations on GHG emissions from oil and natural gas production operations on federal land, given the long-term trend towards increasing regulation in this area. last several years. Moreover, several states have already adopted rules requiring operators of both new and existing sources to develop and implement an LDAR program and to install devices on certain equipment to capture methane emissions. Compliance with these rules could require us to purchase pollution control and leak detection equipment, and to hire additional personnel to assist with inspection and reporting requirements.

Additionally, a number of state and regional efforts are aimed at tracking and/or reducing GHG emissions by means of cap-and-trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. At the international level, there is an agreement, the United Nations-sponsored "Paris Agreement," for nations to limit their GHG emissions through non-binding, individually determined reduction goals every five years after 2020. The United States rejoined the Paris Agreement in February 2021. In early 2021, the Biden Administration issued a moratorium on oil and gas leasing on federal lands and waters to reduce emissions. Since then, the moratorium has been the subject of litigation and, in August 2022, a federal judge entered an injunction against the moratorium. In November 2021, the United States participated in the United Nations Climate Change Conference in Glasgow, Scotland, United Kingdom ("COP26"). COP26 resulted in a pact among approximately 200 countries, including the United States, called the Glasgow Climate Pact. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. In conjunction with COP26, the United States committed to an economy-wide target of reducing net greenhouse gas emissions by 50-52 percent below 2005 levels by 2030. Also in November 2021, President Biden signed a $1 trillion dollar infrastructure bill into law. The new infrastructure law includes several climate-focused investments, including upgrades to power grids to accommodate increased use of renewable energy and expansion of electric vehicle infrastructure. The above-referenced IRA allocated $369 billion to energy and climate initiatives. In November 2022, the United States participated in the United Nations Climate Change Conference in Egypt ("COP27"). In December 2023, the United States participated in the United Nations Climate Change Conference in the United Arab Emirates ("COP28"). Further, several states including New Mexico, and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. Although it is not possible at this time to predict what additional domestic legislation may be adopted in light of the Paris Agreement or the

Glasgow Climate Pact, or how legislation or new regulations that may be adopted based on the Paris Agreement or the Glasgow Climate Pact to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, limiting emissions of GHGs from, our equipment and operations, or restricting federal leases could impair our production, could require us to incur costs to reduce emissions of GHGs associated with our operations and could decrease demand for oil and natural gas.

In September 2023, the Biden Administration directed federal agencies to consider the Social Cost of GHGs metric in budgeting, procurement and other agency decisions, including in environmental reviews, where appropriate. Several states, though none in the areas where we operate, have implemented, of their own accord or in coordination with their neighbor states, regional initiatives and programs limiting, monitoring or otherwise regulating GHG emissions.

The adoption and implementation of any laws or regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require additional expenditures to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas we produce, and thus possibly have a material adverse effect on our revenues, as well as having the potential effect of lowering the value of our reserves. Recently, stakeholders concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Finally, to the extent 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, droughts, floods, and other climatic events, such events could have a material adverse effect on the Company and potentially subject the Company to further regulation. The trend of more expansive and stringent environmental legislation and regulations, including greenhouse gas regulation, could continue, resulting in increased costs of conducting business and consequently affecting our profitability. We also are aware that the SEC intends to propose new and additional rules regarding company disclosure of climate change risk. We will monitor and comply with any such promulgated rules.

Threatened and endangered species migratory birds and natural resources

Various federal and state statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act ("ESA"), the Migratory Bird Treaty Act ("MBTA") and the Clean Water Act. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. As a result of a 2011 settlement agreement, the FWS was required to determine whether to identify more than 250 species as endangered A critical habitat or threatened under the ESA 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. A critical suitable habitat designation could result in further material restrictions on federal land use or on private to land use and could may materially delay or prohibit land access or development. Where takings of or 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 or restrict for oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties may result. Similar protections are offered to migratory birds under the MBTA. Recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds, we believe that we are in substantial compliance with the ESA and the MBTA, and we are not aware of any proposed ESA listings that will materially affect our operations. Nevertheless, we are monitoring listings and proposed listings by the FWS to ensure continued compliance. In November 2022, FWS listed the southern distinct population segments of the lesser prairie-chicken that occupy habitats in eastern New Mexico and the southwest Texas Panhandle. In January 2023, FWS listed the Sacramento Mountains checkerspot butterfly in New Mexico. The federal government in the past has issued indictments under the MBTA to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. In January 2020, a new DOI rule went into effect clarifying that only the intentional taking of protected migratory birds is subject to prosecution under the MBTA. In December 2021, however, that rule was revoked, and a new rule took effect reinstating the prohibition on incidental takes under the MBTA. development. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our the ability to develop and produce reserves within our oil and natural gas reserves. assets. 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.

Operational Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, well blow-outs, pipe failures, industrial accidents, and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil releases, chemical releases, natural gas leaks and the discharge of toxic gases.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us, for example, as a result of damage to our property or equipment or injury to our personnel. These operational risks could also result in the spill or release of hazardous materials such as drilling fluids or other chemicals, which may result in pollution, natural resource damages, or other environmental damage and necessitate investigation and remediation costs. As a result, we could be subject to liability under environmental law or common law theories. In addition, these operational risks could result in the suspension or delay of our operations, which could have significant adverse consequences on our business.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. Under certain circumstances, we may be liable for environmental damage caused by previous owners or operators of properties that we own, lease or operate. As a result, we may incur substantial liabilities to third parties or governmental entities for environmental matters for which we do not have insurance coverage, which could reduce or eliminate funds available for exploration, development or acquisitions or cause us to incur losses.

Human Capital Management

Key to our mission is our employees upon which the foundation of our Company is built. We seek to employ highly trained people who exemplify our core values of honesty and integrity, and are diligent, hard-working individuals who deliver results, and who are good neighbors that contribute to the communities in which they live.

As of December 31, 2022 December 31, 2023, we had 98 108 full-time employees. Our employees are extremely valuable to the success of the Company, and we encourage their collaboration and respect their diverse points of view and opinions. In addition to our full-time employees, the Company also employs a diverse group of independent contractors who assist our full-time staff in a range of areas including geology, engineering, land, accounting, and field operations, as needed. None are represented by labor unions or covered by any collective bargaining agreements.

Diversity and Inclusion**:** The unique backgrounds and experiences of our employees help to develop a wide range of perspectives that lead to better solutions. Our staff's diversity is reflected in our full-time employees where 24% 23% are women and approximately 49% 50% represent minorities. The majority of our employees are citizens of the United States, with a few retaining dual citizenships citizenship in other countries. The employees who are not US citizens, are legally registered to live and work here and the Company is committed to helping those employees retain their ability to remain in the US and continue their employment. The Company is also committed to continuously providing an inclusive work environment where all of our employees can be respected, valued, and successful in achieving their goals, all while contributing to the Company's success.

We recognize that attracting, retaining and developing our employees is critical for our future success. Our Executive Vice President of Land, Legal, Human Resources and Marketing, together with our Chief Executive Officer are responsible for developing and executing our human capital strategy, with oversight by the Board of Directors and the Board committees. Some of our key human capital areas of focus include:

Building a Safe Workforce Starts with Our Culture: Ring is committed to building a safety culture that empowers employees and contractors to act as needed to work safely and to stop the job, without retribution, if conditions are deemed unsafe. We strive to be incident-free every day across our operations. We are focused on building and maintaining a safe workplace for all employees and contractors. The oil and gas industry has a number of inherent risks and our workers are often outdoors, in all seasons and all types of weather. In addition, our field personnel spend significant time driving on a daily basis, putting them at risk for driving incidents. A strong safety culture is essential to our success, and we emphasize the important role that all personnel play in creating and maintaining a safe work environment.

Health and Safety Training and Education: We offer a wide range of training opportunities for employees and contractors to help them develop their skills and understanding of our health and safety policy and programs. In addition to teaching specific skills, these training opportunities encourage personal responsibility for safe operating conditions and help to build a culture of individual accountability for conducting job tasks in a safe and responsible manner.

Ring supports both Company identified and employee identified educational opportunities for employees to advance in their technical and managerial skills and to help provide opportunities to advance throughout our company. Ring's support comes in the form of full or partial funding of educational programs and opportunities, including time off work to attend and/or prepare for such programs.

COVID-19 Response**:** Our COVID-19 management plan was built around the need to support all employees in managing their personal and professional challenges. Frequent and transparent communications are the focus at every level of the organization from those on the front lines to those in our corporate offices. During the early stages of the pandemic, Ring's management team directed the Company's overall COVID-19 pandemic response by implementing all relevant county, state and local government guidelines, directives, and regulations, and developed and adopted work-from-home provisions and procedures, implemented safe working protocols for production teams, assessed and implemented appropriate return-to-office protocols, and provided timely and transparent communications to employees and key stakeholders.

In response to the COVID-19 pandemic, Ring began providing the following benefits to its employees:

- covering the cost of COVID-19 testing through expanded insurance coverage;
- promoting telehealth benefits;
- promoting mental health and well-being plans; and
- providing additional paid sick leave for quarantined employees.

Seasonal Nature of Business

Weather conditions often affect the demand for, and prices of, natural gas and can also delay oil and natural gas drilling, completion, and production activities, disrupting our overall business plans. Generally, the demand for oil and natural gas fluctuates depending on the time of year. Seasonal anomalies such as mild winters and summers may sometimes lessen this fluctuation. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth fiscal quarters. Further, pipelines, utilities, local distribution companies, and industrial end users utilize oil and natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can also lessen seasonal demand. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Available Information

Our website can be found at www.ringenergy.com. Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act will be available through our website free of charge as soon as reasonably practical after we electronically file such material with, or furnish it to, the SEC. The information on, or that can be accessed through, our website is not incorporated by reference into this Annual Report and should not be considered part of this Annual Report. The SEC also maintains a website (http://www.sec.gov) that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC.

Item 1A: Risk Factors

Our business is We are subject to various risks and uncertainties in the ordinary course of our business. The following summarizes significant risks and uncertainties that may adversely affect our business, financial condition, or results of operations. We cannot assure you that any of the events discussed in the risk factors below will not occur. Further, the risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also materially affect our business. Readers should carefully consider the risk factors included below as well as those matters referenced in this Report under "Forward-Looking Statements" and other information included and incorporated by reference into this Report.

Risks Relating to Our Business, Operations, and Strategy

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve additional risks and uncertainties in their application as compared to vertical drilling.

Our operations use some of the latest horizontal drilling and completion techniques as developed by us, other oil and natural gas exploration and production companies and our service providers. The additional risks that we face while drilling horizontally include, but are not limited to, the following:

- drilling wells that are significantly longer and/or deeper than vertical wells;
- landing our wellbores in the desired drilling zones;
- staying in the desired drilling zones while drilling horizontally through the formations;

- running our casing the entire length of wellbores; and
- being able to run tools and other equipment consistently through horizontal wellbores.

Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to fracture or stimulate the planned number of stages in a horizontal or lateral wellbore;
- the ability to run tools and other equipment the entire length of the a wellbore during completion operations; and
- the ability to successfully clean out the a wellbore after completion of the final fracture stimulation stage.

If our assessments of purchased properties are materially inaccurate, it could have a significant impact on future operations and earnings.

The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- unforeseen title issues;
- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment of wells; and
- potential environmental and other liabilities.

Our assessments will not reveal all existing or potential problems, nor will it they permit us to become familiar enough with the potential properties we may acquire to assess fully their capabilities and deficiencies. We plan to undertake further development of our properties generally through the use of cash flow from existing production. Therefore, a material deviation in our assessments of these factors could result in less cash flow being available for such purposes than we presently anticipate, which could either delay future development operations (and delay the anticipated conversion of reserves into cash) or cause us to seek alternative sources to finance development activities.

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

Our prospects are in various stages of evaluation, ranging from prospects that are currently being drilled to prospects that will require substantial additional seismic data processing and interpretation. There is no way We are unable to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. This risk may be enhanced in our situation, due to the fact that a significant percentage of our proved reserves is currently proved undeveloped reserves. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data obtained by analyzing other wells, more fully explored prospects or producing fields will be applicable to all of our drilling prospects.

A substantial percentage of our proved properties are undeveloped; therefore, the risk associated with our success is greater than would be the case if the a substantial majority of our properties were categorized as proved developed.

Because a substantial percentage of our proved properties are proved undeveloped (approximately 35% 32%), we will require significant additional capital to develop such properties before they may become productive. Further, because of the inherent uncertainties associated with drilling for oil and gas, some of these properties may never be developed to the extent that they result in positive cash flow. commercial quantities of oil and natural gas.

While our current business plan is to generally fund the development costs with cash flow from our other producing properties, if such cash flow is not sufficient, we may be forced to seek alternative sources for cash, through the issuance of additional equity or debt securities, increased borrowings or other means.

Hedging transactions may limit our potential gains.

To reduce our exposure to commodity price uncertainty and increase cash flow predictability, relating to the marketing of our crude oil and natural gas, we have entered into crude oil and natural gas price hedging arrangements with respect to a significant portion of our expected production in order to economically hedge a portion of our forecasted oil and natural gas production. Additionally, our credit facility requires us to hedge a significant portion of our production. In addition, these These derivative contracts typically limit the benefit we would otherwise receive from increases in the prices for oil and natural gas. As part of our hedging strategy, we have in place derivative contracts covering percentages of our future estimated production in accordance with our Credit Agreement.

Hedging transactions may expose us to risk of financial loss.

While intended to reduce the effects of volatile oil and natural gas prices, derivative contracts designed as hedges expose us to risk of financial loss in some circumstances, including when there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received, or when the counterparty to the derivative contract is financially constrained and defaults on its contractual obligations. It is also possible that sales volumes fall below the hedged volumes leaving a portion of our position uncovered.

We may be adversely affected by natural disasters, pandemics and other catastrophic events, and by man-made problems such as terrorism, that could disrupt our business operations.

Natural disasters, adverse weather conditions (particularly abnormally cold weather and thunderstorms), floods, pandemics, acts of terrorism and other catastrophic or geo-political events may cause damage or disruption to our operations and the global economy, or could result in market disruptions, any of which could have an adverse effect on our business, operating results, and financial condition.

The coronavirus outbreak has impacted various businesses throughout the world, including an impact on the global demand for oil and natural gas, travel restrictions and the extended shutdown of certain businesses in impacted geographic regions. If other pandemics occur, they could have a material adverse impact on our business operations, operating results and financial condition.

The loss of key members of management or failure to attract and retain other highly qualified personnel could in the future, affect the Company's business results.

The Company's Our success depends on its our ability to attract, retain and motivate a highly-skilled management team and workforce. Failure to ensure that the Company has we have the depth and breadth of management and personnel with the necessary skill sets and experience could impede its our ability to achieve growth objectives and execute its our operational strategy. As the Company continues we continue to expand, it we will need to promote or hire additional staff, and, as a result of increased compensation and benefit packages in our industry, as well as inflation inflationary pressures, it may be difficult to attract or retain such individuals without incurring significant additional costs.

Risks Relating to the Oil and Natural Gas Industry

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price prices we receive for our oil and natural gas production heavily influences influence our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These volatile and we expect these markets will likely continue to be volatile in the future. volatile. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the actions of oil exporting countries that are not members of OPEC;
- the price and quantity of imports and exports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity; activities;
- acts of war and related armed conflicts;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per Boe basis but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices also negatively impact the value of our proved reserves. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or and ability to finance planned capital expenditures.

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

Our future success will depend on our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. For example, in January 2021, President Biden signed an Executive Order directing the Department of Interior (the "DOI") to temporarily pause new oil and gas leases on federal lands and waters pending completion of a comprehensive review of the federal government's existing oil and gas leasing and permitting program. In June 2021, a federal district court enjoined the DOI from implementing the pause and leasing resumed, although litigation over the leasing pause remains ongoing. In February 2022, another judge ruled that the Biden Administration's efforts to raise the cost of climate change in its environmental assessments, would increase energy costs and damage state revenues from energy production. This ruling has cause federal agencies to delay issuing new oil and gas leases and permits on federal lands and waters. While we do not have a significant any federal lands acreage position (240 net acres as of December 31, 2022), at this time, these actions could have a material adverse effect on our industry, the public perception of oil and gas companies such as ours and the willingness of the public and financial institutions to provide capital for our industry.

Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "—Reserve estimates depend on many assumptions that may turn out to be inaccurate." (below) for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular well or project uneconomical. Further, many factors may curtail, delay or cancel drilling, including delays imposed by or resulting from compliance with regulatory requirements; pressure or irregularities in geological formations; shortages of or delays in obtaining equipment and qualified personnel; equipment failures or accidents; adverse weather conditions; reductions in oil and natural gas prices; title problems; and limitations in the market for oil and natural gas.

Decreases in oil and natural gas prices may require us to take write-downs of the financial carrying values of our oil and natural gas properties which could negatively impact the trading value of our common stock.

Accounting rules require that we review periodically the financial carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write-down the financial carrying value of our oil and natural gas properties. A write-down would likely constitute a non-cash charge to earnings. charge. The cumulative effect of a write-down one or more write-downs could also negatively impact the trading price of our common stock.

We follow the full cost method of accounting for our oil and natural gas properties. Under the full cost method, the net book value of properties, less related deferred income taxes, may not exceed a calculated "ceiling." The ceiling is the estimated after tax future net revenues from proved oil and natural gas properties, discounted at 10% per year. Discounted future net revenues are estimated using oil and natural gas spot prices based on the average price during the preceding 12-month period determined as an un-weighted, unweighted arithmetic average of the first-day-of-the-month price for each month within such period, except for changes which are fixed and determinable by existing contracts. The net book value is compared to the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an impairment expense. During the years ended December 31, 2022 December 31, 2023, 2022, and 2021 we did not incur any write-downs. During the year ended December 31, 2020, we recorded a non-cash write-down of $277.5 million. Under SEC full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the financial carrying value of such assets and an equivalent charge to earnings. on our financial statements.

It is difficult to predict with reasonable certainty the amount of any future impairments given the many factors impacting the ceiling test calculation including, but not limited to, future pricing, operating costs, upward or downward reserve revisions, reserve adds, and tax attributes.

Decreases in oil and natural gas prices may affect our bank borrowing base, potentially requiring earlier than anticipated debt repayment, which could negatively impact our financial position, results of operations and the trading value of our common stock.

Decreases in oil and natural gas prices could result in reductions in the borrowing base under our Credit Facility, thus requiring earlier than anticipated repayment of debt or trigger a possible default under our Credit Facility in the event we are unable to make payments or repayments under the Credit Facility on a timely basis.

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

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

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

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

You should not assume that the present value of future net revenues from our reported proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs calculated on the date of the estimate. Discounted future net revenues are estimated using oil and natural gas spot prices based on the average price during the preceding 12-month period determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, except for changes which are fixed and determinable by existing contracts. Actual future prices and costs may differ materially from those used in the present value estimate. If future values decline or costs increase it could negatively impact our ability to finance operations, and individual properties could cease being commercially viable, affecting our decision to continue operations on certain producing properties or to attempt to develop properties. All of these factors would have a negative impact on earnings and net income, and most likely the trading price of our common stock. These factors could also result in the acceleration of debt repayment and a reduction in our borrowing base under our Credit Facility.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured under insured events could materially and adversely affect our business, financial condition and results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination; groundwater;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse; collapses;
- fires and explosions;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our Company. We may elect to not to obtain certain insurance coverage if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, then it could materially and adversely affect us.

Unless we replace our oil and natural gas reserves, our reserves and production will decline as reserves are produced.

Unless we conduct successful exploration and development activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and, therefore, our cash flow and income, are highly dependent on our success in efficiently developing and producing our current reserves and economically finding or acquiring additional recoverable reserves. If we are unable to develop, find or acquire additional reserves to replace our current and future production, our cash flow and income will decline as production declines, until our existing properties would be incapable of sustaining commercial production.

Competition is intense in the oil and natural gas industry.

We operate in a highly competitive environment for acquiring properties and marketing oil and natural gas. Our competitors include multinational oil and natural gas companies, major oil and natural gas companies, independent oil and natural gas companies, individual producers, financial buyers as well as participants in other industries that supply energy and fuel to consumers. Many of our competitors have greater and more diverse resources than we do. Additionally, competition for acquisitions may significantly increase the cost of available properties. We compete for the personnel and equipment required to explore, develop and operate properties. Our competitors also may have established long-term strategic positions and relationships in areas in which we may seek to enter. Consequently, our competitors may be able to address these competitive factors more effectively than we can. If we are not successful in our competition for oil and natural gas reserves properties or in our marketing of production, then our financial condition and operation results may be adversely affected.

If our access to markets is restricted, it could negatively impact our production, our income and our ability to retain our leases.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business.

Currently, the majority some of our production is sold to marketers and other purchasers that have access to nearby pipeline facilities. However, as we further develop Much of our properties, we may find production is in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking or requiring compression facilities. trucking. Further, much of our natural gas production is sold to companies who are the only gathering and processing facilities near most of our properties Such restrictions on our ability to sell our oil or natural gas could have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in increased exposure to facility breakdowns and a lower selling price) prices) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that we or they own.

Many of our properties are in reservoirs that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations by us or other operators could cause depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities conducted on adjacent or nearby wells by us or other operators could cause production from our wells to be shut in shut-in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production from a given pad, which may cause volatility in our operating results. In addition, problems affecting one pad could adversely affect production from all wells on such pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions in ongoing production.

Extreme weather conditions, which could become more frequent or severe due to multiple factors, could adversely affect our ability to conduct drilling, completion and production activities in the areas where we operate.

Our exploration and development activities and equipment could can be adversely affected by extreme weather conditions, such as abnormally low temperatures, which can cause a loss of production from temporary cessation of activity from regional power outages or lost or damaged facilities and equipment. Such extreme For example, we had production stoppages in 2022 and 2023 that adversely affected our revenues. Extreme weather conditions could also impact access to our drilling and production facilities for routine operations, maintenance and repairs and the availability of and our access to, necessary third-party services, such as gathering, processing, compression and transportation services. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operation and capital costs, which could have a material adverse effect on our business, financial condition, and results of operations.

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

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

Our operations are substantially dependent on the availability, use and disposal of water. New legislation and regulatory initiatives or restrictions relating to water disposal wells could have a material adverse effect on our future business, financial condition, operating results and prospects.

Water is an essential component of our drilling and hydraulic fracturing processes. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil, natural gas and NGLs, which could have an adverse effect on our business, financial condition, and results of operations. Wastewaters from our operations typically are disposed of via underground injection. Some studies have linked earthquakes earth tremors in certain areas to underground injection, which has led to greater public scrutiny of disposal wells. Any new environmental initiatives or regulations that restrict injection of fluids, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and gas, or that limit the withdrawal, storage or use of surface water or ground water necessary for hydraulic fracturing of our wells, could increase our operating costs and cause delays, interruptions or cessation of our operations, the extent of which cannot be predicted, and all of which would have an adverse effect on our business, financial condition, results of operations, and cash flows.

Risks Relating to Legal, Regulatory, Privacy, and Tax Matters

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

Exploration, development, production, and sale of oil and natural gas are subject to extensive federal, state, local, and international regulation. It is not possible to predict how or when regulations affecting our operations might change. There is ongoing controversy regarding the leasing of federal lands. For example, at the state level, New Mexico's consideration of legislation to prohibit certain uses of freshwater in fracking operations, implement new disclosure requirements, and increase penalties may affect the cost and feasibility of our business. We may be required to make large expenditures to comply with governmental regulations. Other matters subject to regulation include: discharge permits for drilling operations; drilling bonds; reports concerning operations; the spacing of wells; unitization and pooling of properties; and taxation.

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

Our operations may incur substantial liabilities to comply with the environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state, and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, commences; restrict the types, quantities, and concentration of substances that can be released into the environment in connection with drilling and production activities, activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, areas; and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, penalties; incurrence of investigatory or remedial obligations obligations; or the imposition of injunctive relief. Changes in environmental laws and regulations and the interpretation thereof occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal, or cleanup requirements could require us to make significant expenditures to maintain compliance and may otherwise have a material adverse effect on our results of operations, competitive position, or and financial condition as well as the industry in general. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. The amount of additional future costs is not fully determinable due to such factors as the unknown magnitude of possible contamination, the unknown timing and extent of the corrective actions or compliance efforts that may be required, the determination of the Company's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

Our operations are subject to a series of risks arising out of the perceived threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil and natural gas exploration and production activities, and reduce demand for the oil and natural gas we produce.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. level, though recently passed laws such as the IRA advance numerous climate-related objectives. However, President Biden has highlighted addressing climate change as a priority of his administration, which includes certain potential initiatives for climate change legislation to be proposed and passed into law. Moreover, federal regulators, state and local governments, and private parties have taken (or announced that they plan to take) actions that have or may have a significant influence on our operations. For example, in response to findings that emissions of carbon dioxide, methane, and other GHGs endanger public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources that are already potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA for those emissions. These EPA rules 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 monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations.

The federal regulation of methane from oil and gas facilities has been subject to substantial uncertainty in recent years. In June 2016, the EPA finalized NSPS, known as Subpart OOOOa, that establish emission standards for methane and VOCs from new and modified oil and natural gas production and natural gas processing and transmission facilities. In September 2020, the EPA finalized amendments to the 2016 standards that removed the transmission and storage segment from the oil and natural gas source category and rescinded the methane-specific requirements for production and processing facilities. However, President Biden signed an executive order on his first day in office calling for the suspension, revision, or rescission of the September 2020 rule and the reinstatement or issuance of methane emission standards for new, modified and existing oil and gas facilities. Subsequently, the U.S. Congress approved, and President Biden has signed into law, a resolution under the Congressional Review Act to repeal the September 2020 revisions to the methane standards, effectively reinstating the prior standards. In response to President Biden's executive order in November 2021, calling on the EPA issued a proposed rule that, if to revisit federal regulations regarding methane, the EPA finalized would establish Quad Ob more stringent methane rules for new, modified, and reconstructed facilities, known as new source and Quad Oc OOOOb, as first-time well as standards for existing source standards of performance for methane and VOC emissions sources for the crude oil first time ever, known as OOOOc, in December 2023. Under the final rules, states have two years to prepare and natural gas source category. Owners or operators of affected submit their plans to impose methane emission units or processes would have to comply with specific controls on existing sources. The presumptive standards of performance that may established under the final rule are generally the same for both new and existing sources. The requirements include enhanced leak detecting detection survey requirements using optical gas imaging and subsequent repair requirements, other advanced monitoring to encourage the deployment of innovative technologies to detect and reduce methane emissions, reduction of regulated emissions by 95% through capture and control systems and zero-emission requirements for certain equipment or processes devices. The rule also establishes a "super emitter" response program that would allow third parties to make reports to EPA of large methane emission events, triggering certain investigation and operations repair requirements. Fines and maintenance requirements. In November 2022, penalties for violations of these rules can be substantial. It is likely, however, that the EPA published a supplemental proposal, which, among other items, final rule and its requirements will be subject to legal challenges. Moreover, compliance with the new rules may affect the amount we owe under the IRA 2022's methane fee described above because compliance with EPA's methane rules would impose expanded inspection, monitoring exempt an otherwise covered facility from the requirement to pay the methane fee. The requirements of the EPA's final methane rules have the potential to increase our operating costs and emissions control requirement on oil thus may adversely affect our financial results and gas sites, cash flows. Moreover, failure to comply with these CAA requirements can result in the imposition of substantial fines and penalties as well as strengthen requirements related to emissions from equipment and routine flaring. The proposal would also establish a "Super Emitter Response Program" that would require operator response to emissions events exceeding 200 pounds per hour, as detected by regulatory authorities or qualified third-parties. The proposal is currently subject to public comment and is expected to be finalized in 2023. Separately, certain provisions of the IRA 2022 address methane regulation by imposing the first federal fee on excess methane emissions. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. costly injunctive relief. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and gas industry remain a significant possibility.

Internationally, the United Nations-sponsored "Paris Agreement" requires member states to individually determine and submit non-binding emissions reduction targets every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50-52% below 2005 levels by 2030. In November 2021, the international community gathered again at COP26, during which multiple announcements were made, including a call for parties to eliminate certain oil and natural gas subsidies and pursue further action on non-CO2 GHGs. These goals were reaffirmed at COP27 in November 2022. Relatedly, the United States and European Union jointly announced the launch of the "Global Methane Pledge," which aims to cut global methane pollution at least 30% by 2030 relative to 2020 levels, including "all feasible reductions" in the energy sector. At COP28 in December 2023, the parties signed onto an agreement to transition away from fossil fuels in energy systems and increase renewable energy capacity, though no timeline for doing so was set. While non-binding, the agreements coming out of COP28 could result in increased pressure among financial institutions and various stakeholders to reduce or otherwise impose more stringent limitations on funding for and increase potential opposition to the exploration and production of fossil fuels. The impacts of these orders, pledges, agreements and any legislation or regulation promulgated to fulfill the United States' commitments under the Paris Agreement, COP26, COP28 or other international conventions cannot be predicted at this time. Concern over the threat of climate change has also resulted in increasing political risks in the United States, including climate-change related pledges made by President Biden and other public office representatives. On January 27, 2021, President Biden signed an executive order calling for substantial action on climate change, including, among other things, the increased use of zero-emissions vehicles by the federal government, the elimination of subsidies provided to the oil and natural gas industry, and increased emphasis on climate-related risks across agencies and economic sectors. Additionally, in November 2021, the Biden Administration released "The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050," which establishes a roadmap to net zero emissions in the United States by 2050 through, among other things, improving energy efficiency; decarbonizing energy sources via electricity, hydrogen, and sustainable biofuels; and reducing non-CO2 GHG emissions, such as methane and nitrous oxide.

In addition, on March 6, 2024, the SEC adopted a rule requiring registrants to include certain climate-related disclosures, including Scope 1 and 2 GHG emissions, climate-related targets and goals, and certain climate-related financial statement metrics, in registration statements and annual reports. Currently, the ultimate impact of these laws on our business is uncertain. Separately, enhanced climate related disclosure requirements could lead to reputational or other harm with customers, regulators, investors or other stakeholders and could also increase our litigation risks relating to statements alleged to have been made by us or others in our industry regarding climate change risks, or in connection with any future disclosures we may make regarding reported emissions, particularly given the inherent uncertainties and estimations with respect to calculating and reporting GHG emissions. Additionally, the SEC has also from time to time applied additional scrutiny to existing climate-change related disclosures in public filings, increasing the potential for enforcement if the SEC were to allege an issuer's existing climate disclosures misleading or deficient.

Increasingly, oil and natural gas companies are exposed to litigation risks associated with the threat of climate change. A number of parties have brought lawsuits against oil and natural gas companies in state or federal court for alleged contributions to, or failures to disclose the impacts of, climate change. We are not currently party to any such litigation, but could be named in future actions making similar claims of liability. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Additionally, in response to concerns related to climate change, companies in the oil and natural gas industry may be exposed to increasing financial risks. Financial institutions, including investment advisors and certain sovereign wealth, pension and endowment funds, may elect in the future to shift some or all of their investments into non-oil and natural gas 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 in the future not to provide funding for oil and natural gas companies. Many of the largest U.S. banks have made net zero commitments and have announced that they will be assessing financed emissions across their portfolios and taking steps quantify and reduce those emissions. In addition, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that commitments from over 450 firms across 45 countries had resulted in over $130 trillion in capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing and/or underwriting activities to net zero emissions by 2050. These and other developments in the financial sector could lead to some lenders restricting access to capital for or divesting from certain industries or companies, including the oil and natural gas sector, or requiring that borrowers take additional steps to reduce their GHG emissions. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the oil and natural gas industry. For example, the Federal Reserve has joined the Network for Greening the Financial System ("NGFS"), a consortium of financial regulators focused on addressing climate-related risks in the financial sector and, in November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. A material reduction in the capital available to the oil and natural gas industry could make it more difficult to secure funding for exploration, development, production, transportation and processing activities, which could result in decreased demand for our products or otherwise adversely impact our financial performance.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives related to climate change or GHG emissions from oil and natural gas facilities could result in increased costs of compliance or costs of consumption, thereby reducing demand for, oil and natural gas. Additionally, political, litigation, and financial risks may result in (i) restriction or cancellation of certain oil and natural gas production activities, (ii) incurrence of obligations for alleged damages resulting from climate change, or (iii) impairment of our ability to continue operating in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition, and results of operations.

Moreover, climate change may also result in various physical risks such as the increased frequency or intensity of extreme weather events or changes in meteorological and hydrological patterns, that could adversely impact our financial condition and operations, as well as those of our suppliers or customers. Such physical risks may result in damage to our facilities, or otherwise adversely impact our operations, such as if we become subject to water use curtailments in response to drought, or demand for our products, such as to the extent warmer winters reduce the demand for energy for heating purposes. Such physical risks may also impact the infrastructure on which we rely to produce or transport our products. One of more of these developments could have a material adverse effect on our business, financial condition and operations. In addition, while our consideration of changing weather conditions and inclusion of safety factors in design is intended to reduce the uncertainties that climate change and other events may potentially introduce, our ability to mitigate the adverse impacts of these events depends in part on the effectiveness of our facilities and our disaster preparedness and response and business continuity planning, which may not have considered or be prepared for every eventuality.

Changes in tax laws or the interpretation thereof or the imposition of new or increased taxes or fees may adversely affect our operations operating results and cash flows.

From time to time, federal and state level legislation has been proposed that would, if enacted into law, make significant changes to tax laws, including to certain key federal and state income tax provisions currently available applicable to oil and natural gas exploration and development companies. Such legislative changes have included, but have not been limited to, (i) the elimination of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) an extension of the amortization period for certain geological and geophysical expenditures, (iv) the elimination of certain other tax deductions and relief previously available to oil and natural gas companies, and (v) an increase in the federal income tax rate applicable to corporations such as us. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on oil and natural gas extraction. The passage of any legislation as a result of these proposals and other similar changes in federal income tax laws or the imposition of new or increased taxes or fees on oil and natural gas extraction could adversely affect our operations operating results and cash flows.

In addition, on August 16, 2022, President Biden signed into law the IRA, which includes, among other things, a corporate alternative minimum tax (the "CAMT"), provides for an investment tax credit for qualified biomass property and introduces a one percent excise tax on corporate stock repurchases after December 31, 2022. repurchases. Under the CAMT, a 15 percent minimum tax will be imposed on certain adjusted financial statement income of "applicable corporations," which is was effective beginning January 1, 2023. 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. We Based on our current interpretation of the IRA and the CAMT and a number of operational, economic, accounting and regulatory assumptions, we do not anticipate the CAMT materially increasing our U.S. federal income tax liability in the near term. The foregoing analysis is based upon our current interpretation of the provisions contained in the IRA and the CAMT. In the future, the U.S. Department of Treasury and the Internal Revenue Service are currently assessing the potential impact of these legislative changes and will continue expected to evaluate the overall impact of other current, future and proposed release regulations and interpretive guidance relating to the CAMT, and any significant variance from tax our current interpretation could result in a change in the expected application of the CAMT to us and adversely affect our operating results and cash flows.

Also, we are subject to unclaimed or abandoned property (escheat) laws which require us to turn over to certain government authorities on our effective tax rate and consolidated balance sheets. the property of others held by us that has been unclaimed for a specified period. We are unable subject to predict whether any such changes or other proposals will ultimately be enacted. audits by individual U.S. states regarding our escheatment practices. The legislation and regulations related to unclaimed property matters are complex and subject to varying interpretations by state governmental authorities.

New climate disclosure rules proposed by the SEC may increase our costs of compliance and adversely impact our business.

On March 21, 2022 March 6, 2024, the SEC proposed adopted new rules relating to the disclosure of a range of climate-related risks. We are currently assessing the proposed final rule, but at this time we cannot predict the costs of implementation or any potential adverse impacts resulting from the rule. According to the SEC's Fall 2022 regulatory agenda, the proposed climate disclosure rule is scheduled to be finalized in April 2023. To the extent As a result of this rule, is finalized as proposed, we could incur increased costs relating to the assessment and disclosure of climate-related risks, including increased legal, accounting and financial compliance costs, as well as making some activities more difficult, time-consuming and costly, and placing strain on our personnel, systems, and resources. We may also face increased litigation risks related to disclosures made pursuant to the rule if finalized as proposed. rule. In addition, enhanced climate disclosure requirements could accelerate the trend of certain stakeholders and lenders restricting or seeking more stringent conditions with respect to their investments in certain carbon-intensive sectors. The SEC proposes certain phase-in compliance dates for disclosures under the proposed rules, including for GHG emissions metrics.

Risks Relating to Our Capital Structure

We have significant indebtedness.

We have a Credit Facility in place with $600.0 $600 million in commitments from borrowings and letters of credit under our Second Amended and Restated Credit Agreement dated August 31, 2022 with Truist Bank as Administrative Agent (" (the "Second Credit Agreement"). As of December 31, 2022 December 31, 2023, $415.0 $425.0 million was outstanding on our Credit Facility. If we further utilize this facility, the level of our indebtedness could affect our operations in several ways, including the following:

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

In addition, our bank borrowing base is subject to semi-annual redeterminations. We could be required to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are required to do so, we may not have sufficient funds to make such repayments, and we may need to negotiate renewals of our borrowings or arrange new financing or sell significant assets. Any such actions could have a material adverse effect on our business and financial results. Further, our borrowings under our Credit Facility expose us to interest rate risks, as it bears variable interest based upon a prime rate and is therefore susceptible to interest rate fluctuations.

We may be unable to access the equity or debt capital markets to meet our obligations.

Our plans for growth may include accessing the capital markets. Recent reluctance to invest in the exploration and production sector based on market volatility, historically perceived underperformance, and Environmental, Social and Governance ("ESG") ESG trends, among other things, has raised concerns regarding capital availability for the sector. If those markets are unavailable, or if we are unable to access alternative means of financing on acceptable terms, we may be unable to implement all of our development plans, make acquisitions, or otherwise carry out 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.

We continue to be impacted by inflationary pressures on our operating costs and capital expenditures.

Beginning in the second half of 2021 and continuing throughout 2022, 2023, we, similar to other companies in our industry, experienced inflationary pressures on our operating costs and capital expenditures - namely the costs of fuel, steel (i.e., wellbore tubulars), labor, and drilling and completion services. Such inflationary pressures on our operating and capital costs, which we currently expect to continue in 2023, 2024, have impacted our cash flows and results of operations. We have undertaken, and plan to continue with, certain initiatives and actions (such as agreements with service providers to secure the costs and availability of services) to mitigate such inflationary pressures. However, there can be no assurance that such efforts will offset, largely or at all, the impacts of any future inflationary pressures on our operating costs and capital expenditures and, in turn, our cash flows and results of operations.

Risks Relating to Technology and Cybersecurity

We rely on computer and telecommunications systems, and failures in our systems or cyber security attacks or breaches could result in information theft, data corruption, disruption in operations and/or financial loss.

The oil and natural gas industry has become increasingly dependent upon digital technologies to conduct day-to-day operations including certain exploration, development, and production activities. We depend on digital technology to process and record financial and operating data, estimate quantities of oil and natural gas reserves, analyze seismic and drilling information, process and store personally identifiable information on our employees and royalty owners, and communicate with our employees and other third parties. Our business partners, including vendors, service providers, purchasers of our production, and financial institutions, are also dependent on digital technology. It is possible that we could incur interruptions from cyber security cybersecurity attacks or breaches, computer viruses or malware that could result in disruption of our business operations and/or financial loss. Although we utilize various procedures and controls to monitor and protect against these threats and mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing and causing us to suffer losses in the future. Even so, any cyber incidents or interruptions to our computing and communications infrastructure or our information systems could lead to data corruption, communication interruption, unauthorized release, gathering, monitoring, misuse, or destruction of proprietary or other information, or otherwise significantly disrupt our business operations. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities.

Risks Relating to Our Common Stock

We have recently registered 63,888,878 shares of our common stock for possible resale by certain of our stockholders, and have exercisable warrants for 14,590,366 shares of common stock, resulting in significant "market overhang" of our common stock.

In connection with the recently completed Stronghold Acquisition we registered 63,888,878 completed in 2022, Warburg Pincus & Company US, LLC and its affiliates hold approximately 46.1 million shares of our common stock with the SEC for possible resale by Stronghold stockholders. stock. This represents approximately 35% 23% of our presently outstanding shares of common stock and if the selling stockholders choose to sell all or a large number of their shares, from time to time, it likely would have a depressive effect on the market price of our common stock. In addition, we have outstanding warrants with respect to 14,590,366 shares of common stock with an exercise price of $0.80 per share that have been registered for resale. The holders could choose to sell the shares of common stock acquired upon exercise of their warrants, which could also have a depressive effect on the market price of our common stock.

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

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

- our operating and financial performance and prospects;
- variations in our quarterly operating results and changes in our liquidity position;
- investor perceptions of us and the industry and markets in which we operate;
- future sales, or the availability for sale, of equity or equity-related securities;
- changes in securities analysts’ estimates of our financial performance;
- changes in market valuations of similar companies;
- changes in the price of oil and natural gas; and
- general financial, domestic, economic, and other market conditions.

We currently do not pay cash dividends on our common stock.

We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements, and investment opportunities. In addition, the terms of our Second Credit Agreement have restrictions on dividend payments to our equity holders, including our common stockholders.

Our board of directors can, without stockholder approval, cause preferred stock to be issued on terms that could adversely affect common stockholders.

Under our Articles of Incorporation, our board of directors is authorized to issue up to 50,000,000 shares of preferred stock, of which none are issued and outstanding as of the date of this Annual Report. Also, our board of directors, without stockholder approval, may determine the price, rights, preferences, privileges, and restrictions, including voting rights, of those shares. If the board of directors causes shares of preferred stock to be issued, the rights of the holders of our common stock could be adversely affected. The board of director’s ability to determine the terms of preferred stock and to cause its issuance, while providing desirable flexibility in connection with possible acquisitions and other corporate purposes, could have the effect of making it more difficult for a third party to acquire a majority of our outstanding voting stock. Preferred shares issued by the board of directors could include voting rights, or even super voting rights, which could shift the ability to control the Company to the holders of the preferred stock. Preferred shares could also have conversion rights into shares of common stock at a discount to the market price of the common stock which could negatively affect the market for our common stock. In addition, preferred shares would typically have preference in the event of liquidation of the Company, which means that the holders of preferred shares would be entitled to receive the net assets of the Company distributed in liquidation before the common stockholders receive any distribution of the liquidated assets. We have no current plans to issue any shares of preferred stock.

Provisions under Nevada law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

In addition to the ability of the board of directors to issue preferred stock, the existence of some provisions under Nevada law could delay or prevent a change in control of the Company, which could adversely affect the price of our common stock. Nevada law imposes some restrictions on mergers and other business combinations between us and any holder of 10% or more of our outstanding common stock.

Item 1B: Unresolved Staff Comments

None.

Item 1C: Cybersecurity

Cybersecurity Risk Management

We have developed and implemented a cybersecurity risk management program intended to protect the confidentiality, integrity, and availability of our critical systems and information. We design and assess our cybersecurity risk management program based on the National Institute of Standards and Technology Cybersecurity Framework (“NIST”). This does not imply that we meet any particular technical standards, specifications, or requirements, only that we use the NIST as a guide to help us identify, assess, and manage cybersecurity risks relevant to our business.

Our cybersecurity risk management program is integrated into our overall enterprise risk management program, and shares common methodologies, reporting channels and governance processes that apply across the enterprise risk management program to other legal, compliance, strategic, operational, and financial risk areas.

Our cybersecurity risk management program includes, but is not limited to, the following key elements:

- risk assessments designed to help identify material cybersecurity risks to our critical systems and information;
- a Manager of Information Technologies (“IT Manager”) responsible for managing our cybersecurity risk assessment processes, our security controls, and our response to cybersecurity incidents;
- the use of external service providers, where appropriate, to assess, test or otherwise assist with aspects of our security processes;
- systems for protecting information technology systems and monitoring for suspicious events, such as threat protection, firewall and anti-virus software; and
- cybersecurity awareness training of our employees, including incident response personnel, and senior management.

Governance

Our board of directors (the “Board”) considers oversight of our risks and risk management activities, including those related to cybersecurity threats, to be a responsibility of the entire Board. The Board also delegates certain risk oversight responsibilities to certain of its committees, and oversight of our cybersecurity risk is delegated by the Board to its Audit Committee. The Audit Committee receives regular reports, typically on a quarterly basis, from management and our internal auditors regarding information technology, cybersecurity risk, and efforts to prevent and mitigate such risks. The Chairperson of the Audit Committee subsequently reports on the Company’s cybersecurity risk, monitoring, and mitigation activities to the full Board, which equips the Board and its committees to fulfill their risk oversight role.

The Board and Audit Committee are supported in their oversight capacity by our Management Cybersecurity Committee (the “MC Committee”) and our internal auditors. The MC Committee consists of our CEO, CFO, EVP of Engineering and Corporate Planning, and our IT Manager.

Our internal auditors perform audit engagements to assess our strategies, policies, procedures, and controls to reduce the risk of a cybersecurity incident.

Our IT Manager is responsible for assessing and managing risks from cybersecurity threats, our overall cybersecurity risk management program and supervises both our internal cybersecurity personnel and our retained external cybersecurity consultants. Our IT Manager is responsible for reporting material incidents to our MC Committee. Our IT Manager has a Bachelor of Science in Computer Science from Texas A&M University and a Master of Business Administration from Rice University. He has over fifteen years of information technology experience in the energy industry.

Our MC Committee stays informed about and monitors efforts to prevent, detect, mitigate, and remediate cybersecurity risks and incidents through various means, including, as appropriate, briefings from internal security personnel, threat intelligence and other information obtained from governmental, public or private sources, such as external consultants engaged by us, and alerts and reports produced by security tools deployed in the information technology environment.

Engagement of Third Parties

The MC Committee, internal auditors, our IT Manager and various other groups each occasionally engage third-party service providers to assist in their management of cybersecurity threats, including but not limited to cybersecurity vendors, assessors, consultants, auditors, and other third parties. Our IT Manager oversees third party vendors to identify cyber risks associated with our use of third-party service providers who may have access to sensitive Company data and systems.

Impact of Risks from Cybersecurity Threats

As of the date of this Annual Report, we are not aware of any cybersecurity threats, including as a result of any previous cybersecurity incidents, that have materially affected or are reasonably likely to materially affect us, including our operations, business strategy, results of operations or financial condition. However, we acknowledge that cybersecurity threats are continually evolving, and the possibility of future discovery of cybersecurity incidents remains. Please see “Part I, Item 1A. Risk Factors – Risks Related to Technology and Cybersecurity” for additional information about our cybersecurity risks. There can be no assurance that our cybersecurity risk management program, including our controls, procedures and processes, will be fully complied with or that our program will be fully effective in protecting the confidentiality, integrity and availability of our information systems. While we devote resources to our security measures to protect our systems and information, these measures cannot provide absolute security that they will not be subject to cybersecurity attacks and any damages to us from such attacks.

Item 2: Properties

General Background

Ring is engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas.

Management's Business Strategy Related to Properties

Our goal is to increase stockholder value by investing in oil and natural gas projects with attractive rates of return on capital employed. We plan to achieve this goal by developing our existing oil and natural gas properties and pursuing strategic acquisitions of additional properties.

Developing Existing Properties

We believe that there is significant value to be created by drilling the undeveloped opportunities on our properties. As of December 31, 2022 December 31, 2023, we owned interests in a total of 101,773 76,484 gross (87,326 (65,462 net) developed acres and operate the vast majority of our acreage position. In addition, as of December 31, 2022 December 31, 2023, we owned interests in approximately 22,444 19,643 gross (14,849 (15,073 net) undeveloped acres. While our near-term plans are focused on drilling wells on our existing acreage to develop the potential contained therein, our long-term plans also include continuing to evaluate acquisition and leasing opportunities that can earn attractive rates of return on capital employed. Within the Northwest Shelf, we have a total of 73 48 proved undeveloped locations (85% horizontal (100% horizontal) and 15% vertical) and 19 4 PDNP opportunities based on the reserve report as of December 31, 2022 December 31, 2023. Our reserve estimates account for the capital costs required to develop these wells. wells and the future plugging and abandonment cost. We believe the Northwest Shelf leases contain additional potential drilling locations. Within the Central Basin Platform, we have had a total of 141 163 proved undeveloped locations (21% (13% horizontal and 79% 87% vertical) and 205 238 PDNP opportunities based on the reserve report as of December 31, 2022 December 31, 2023. Our reserve estimates account for the capital costs required to develop these wells. We believe the Central Basin Platform leases contain additional potential drilling locations.

Pursuing Profitable Acquisitions

We have historically pursued acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have an experienced team of management, engineering, geoscience, and land professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties.

Summary of Oil and Natural Gas Properties and Projects

Significant Operations

The Company's significant operations are in two core areas which it has actively drilled over the last several years located in the Northwest Shelf and the Central Basin Platform of the Permian Basin.

Northwest Shelf –Yoakum Runnels and Coke County, Texas and Lea County, New Mexico – In 2019, we acquired properties consisting of 49,754 gross (38,230 net) acres with an average working interest of 77% and an average net revenue interest of 58%. As of December 31, 2022 December 31, 2023, we owned interests in a total of 18,270 12,572 gross (13,930 (8,751 net) developed acres and 18,539 16,258 gross (12,512 (12,405 net) undeveloped acres. acres with an average proved operated working interest of 89% and net revenue interest of 67%. As of December 31, 2022 December 31, 2023, the Company had interests in approximately 27 five gross vertical and 139 146 gross horizontal producing wells, of which we operate 27 five vertical and 108 111 horizontal wells. The horizontal wells predominately produce from the San Andres conventional reservoir and the verticals produce from Wolfcamp and Devonian reservoirs.

Central Basin Platform - Andrews, Gaines, Crane, Ector, Winkler, and Ward Counties, Texas leases – In 2011, we acquired a 100% working interest and a 75% net revenue interest in our initial leases in Andrews and Gaines counties. Since that time, we have acquired working and net revenue interests in additional producing leases and acquired additional undeveloped acreage in and around our Andrews County and Gaines County leases. In 2022, we acquired properties consisting of approximately 37,000 net acres, with an average working interest of 99% and an average net revenue interest of 88% for oil and 96% for natural gas in our initial leases in Crane, Winkler, and Ward counties. In 2023, we acquired properties in Ector County. As of December 31, 2022 December 31, 2023, we owned interests in a total of 64,774 63,912 gross (54,959 (56,711 net) developed acres and 3,905 3,385 gross (2,337 (2,668 net) undeveloped acres. acres with an average proved operated working interest of 97% and net revenue interest of 82% in the area. As of December 31, 2022 December 31, 2023, the Company had interests in approximately 625 695 gross vertical and 195 197 gross horizontal producing wells, of which we operate 518 587 vertical and 193 195 horizontal wells. The horizontal wells predominately produce from the San Andres conventional reservoir and the verticals produce from a variety of conventional pay sands including Holt, Glorieta, Clear Fork, Wichita Albany, Tubb, Wolfcamp and Devonian reservoirs.

Title to Properties

We generally conduct a preliminary title examination prior to the acquisition of properties or leasehold interests. Prior to commencement of operations on such acreage, a thorough title examination is usually conducted and any significant defects are remedied before proceeding with operations. We believe the title to our leasehold properties is good, defensible and customary with practices in the oil and natural gas industry, subject to such exceptions that we believe do not materially detract from the use of such properties. With respect to our properties of which we are not the record owner, we rely on contracts with the owner or operator of the property or assignment of leases, pursuant to which, among other things, we generally have the right to have our interest placed on record.

Our properties are generally subject to royalty, overriding royalty and other interests customary in the industry, liens incident to lending agreements, current taxes and other customary burdens, minor encumbrances, easements and restrictions. We do not believe any of these burdens will materially interfere with our use of these properties.

Summary of Oil and Natural Gas Reserves

As of December 31, 2022 December 31, 2023, our estimated proved reserves had a pre-tax PV-10 value (present value discounted at 10%) of approximately $2,773.7 million $1,647.0 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $2,272.1 million $1,399.2 million, 100% over 99.6% of which relates to our properties in the Permian Basin in Texas and New Mexico. Texas. We spent approximately $360.1 million $544.2 million on acquisitions and capital projects during 2022 2023 and 2021. 2022. We expect to further develop these properties through additional drilling.

The following table summarizes our total net proved reserves, pre-tax PV-10 value and Standardized Measure of Discounted Future Net Cash Flows as of December 31, 2022 December 31, 2023. All Approximately 99.8% of our proved reserves are in the Permian Basin in Texas and New Mexico. Texas.

Oil (Bbl)	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Liquids (Bbl)	Total (Boe) (1)	Pre-Tax PV-10 Value (2)	Standardized Measure of Discounted Future Net Cash Flows	Oil (Bbl)	Natural Gas (Mcf)	Natural Gas Liquids (Bbl)	Total (Boe) (1)	Pre-Tax PV-10 Value (2)	Standardized Measure of Discounted Future Net Cash Flows
88,704,743		157,870,449	23,105,658	138,122,143	$2,773,656,500	$2,272,113,518						
82,141,277												

(1) Six Mcf is deemed the equivalent of one Boe.

(2) PV-10 is a non-GAAP financial measure. See below for a reconciliation.

We present the pre-tax PV-10 value, which is a non-GAAP financial measure, because it is a widely used industry standard which we believe is useful to those who may review this Report when comparing our asset base and performance to other comparable oil and natural gas exploration and production companies. PV-10 is a non-GAAP measure that differs from a measure under accounting principles generally accepted in the United States ("GAAP") known as “standardized measure of discounted future net cash flows” in that PV-10 is calculated without including future income taxes. PV-10 does not necessarily represent the fair market value of oil and natural gas properties. PV-10 is not a measure of financial or operational performance under GAAP, nor should it be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows as defined under GAAP.

The table below provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows (*in thousands*):

Present value of estimated future net revenues (PV-10)	$ 2,773,657 1,647,031,127
Future income taxes, discounted at 10%	$ 501,543 247,845,936
Standardized measure of discounted future net cash flows	$ 2,272,114 1,399,185,191

Reserve Quantity Information

Our estimates of proved reserves and related valuations are based on reports independently determined and prepared by Cawley, Gillespie & Associates, Inc. ("CGA"), independent petroleum engineers. These reserves are attributable solely to properties within the United States. A summary of the changes in quantities of proved (developed and undeveloped) oil, natural gas and natural gas liquid reserves is shown below.

		Oil (Bbl)	Gas (Mcf)	Natural Gas Liquids (Bbl) (2)	Boe(1)		Oil (Bbl)	Gas (Mcf)(2)	Natural Gas Liquids (Bbl)(2)	Boe(1)
Balance, December 31, 2020		66,264,286	61,305,027	—	76,481,791					
	Oil (Bbl)									
Balance, December 31, 2021						Balance, December 31, 2021	65,838,609	71,773,789	—	77,800,907
Purchase of minerals in place	Purchase of minerals in place	2,180,497	824,512	—	2,317,916	Purchase of minerals in place	28,086,920	108,456,107	16,715,626	62,878,564

Extensions, discoveries and improved recovery	Extensions, discoveries and improved recovery	3,975,675	5,172,392	—	4,837,740	Extensions, discoveries and improved recovery	628,978	522,178	52,810	768,818
Sales of minerals in place	Sales of minerals in place	(462,970)	(555,879)	—	(555,617)	Sales of minerals in place	—			—
Production	Production	(2,686,940)	(2,535,188)	—	(3,109,471)	Production	(3,459,477)	(4,088,642)	(371,337)	(4,512,254)
Revisions of previous quantity estimates	Revisions of previous quantity estimates	(3,431,939)	7,562,925	—	(2,171,452)	Revisions of previous quantity estimates	(2,390,287)	(18,792,983)	6,708,559	1,186,108
Balance, December 31, 2021		65,838,609	71,773,789	—	77,800,907					
Balance, December 31, 2022						**Balance, December 31, 2022**	88,704,743	157,870,449	23,105,658	138,122,143
Purchase of minerals in place	Purchase of minerals in place	28,086,920	108,456,107	16,715,626	62,878,564					
Purchase of minerals in place										
Purchase of minerals in place							6,543,640	3,372,965	1,089,382	8,195,183
Extensions, discoveries and improved recovery	Extensions, discoveries and improved recovery	628,978	522,178	52,810	768,818	Extensions, discoveries and improved recovery	3,098,845	4,113,480	1,014,343	4,798,768
Sales of minerals in place						Sales of minerals in place	(4,897,921)	(2,674,955)	(392,953)	(5,736,700)
Production	Production	(3,459,477)	(4,088,642)	(371,337)	(4,512,254)	Production	(4,579,942)	(6,339,158)	(976,852)	(6,613,320)
Revisions of previous quantity estimates	Revisions of previous quantity estimates	(2,390,287)	(18,792,983)	6,708,559	1,186,108	Revisions of previous quantity estimates	(6,728,088)	(9,946,459)	(621,014)	(9,006,845)
Balance, December 31, 2022		88,704,743	157,870,449	23,105,658	138,122,143					
Balance, December 31, 2023						**Balance, December 31, 2023**	82,141,277	146,396,322	23,218,564	129,759,229

(1) Six Mcf is deemed the equivalent of one Boe.

(2) At year-end 2022, we began reporting reserves on a three-stream basis, including natural gas liquids NGLs separately from natural gas.

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history, five year rule and/or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During Notable changes in proved reserves for the year ended December 31, 2022, our December 31, 2023 included the following:

- *Extensions.* In 2023, extensions and discoveries of 769 MBoe (one thousand Boe) resulted 4.8 MMBoe were primarily from the 2022 result of the successful operated drilling program and non-operated activity in the Northwest Shelf and Central Basin Platform as well as non-operated activity Platform.

- *Purchase of minerals in place.* In 2023, the Northwest Shelf. Revisions Company completed the acquisition of 1,186 MBoe were predominately Founders oil and gas leases and related property within Ector County that resulted in 8.2 MMBoe in additional reserves.

- *Sales of minerals in place.* In 2023, the result Company sold 5.7 MMBoe from the divestiture of converting from two-stream the Delaware Basin assets (30%), the New Mexico operated assets (57%), and part of the Company's assets in Gaines County (13%).

- *Revision of previous estimates.* In 2023, the negative revisions of prior reserves of 9.0 MMBoe consisted of 5.3 MMBoe (59%) related to three-stream reserves, the removal of proved undeveloped reserves changes in our Delaware asset, well price and 3.7 MMBoe (41%) related to changes in performance increased cost from 2022 industry activity, and increased commodity pricing. other economic factors.

Our proved oil, natural gas and natural gas liquid reserves are shown below.

		For the years ended December 31,				
		2022	2021			
	For the years ended December 31,				For the years ended December 31,	
	2023				2023	2022
Oil (Bbl)	**Oil (Bbl)**					
Developed						
Developed						
Developed	Developed	57,012,137	36,820,824		56,029,039	57,012,137
Undeveloped	Undeveloped	31,692,606	29,017,785	Undeveloped	26,112,238	31,692,606
Total	**Total**	88,704,743	65,838,609	**Total**	82,141,277	88,704,743
Natural Gas (Mcf)	**Natural Gas (Mcf)**					
Natural Gas (Mcf)						
Natural Gas (Mcf)						
Developed						
Developed						
Developed	Developed	106,399,050	39,748,880		99,896,022	106,399,050
Undeveloped	Undeveloped	51,471,399	32,024,909	Undeveloped	46,500,300	51,471,399
Total	**Total**	157,870,449	71,773,789	**Total**	146,396,322	157,870,449
Natural Gas Liquids (Bbl)	**Natural Gas Liquids (Bbl)**					
Natural Gas Liquids (Bbl)						
Natural Gas Liquids (Bbl)						
Developed						
Developed						
Developed	Developed	15,332,804	—		15,449,907	15,332,804
Undeveloped	Undeveloped	7,772,854	—	Undeveloped	7,768,657	7,772,854
Total	**Total**	23,105,658	—	**Total**	23,218,564	23,105,658
Total (Boe)1						
Total (Boe) (1)						
Total (Boe) (1)						
Total (Boe) (1)						
Developed						
Developed						
Developed	Developed	90,078,116	43,445,637		88,128,284	90,078,116
Undeveloped	Undeveloped	48,044,027	34,355,270	Undeveloped	41,630,945	48,044,027
Total	**Total**	138,122,143	77,800,907	**Total**	129,759,229	138,122,143

(1) Six Mcf is deemed the equivalent of one Boe.

Standardized Measure of Discounted Future Net Cash Flows

Our standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and changes in the standardized measure as described below were prepared in accordance with GAAP.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pre-tax net cash flows relating to proved oil and natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value of our oil and natural gas properties.

Our estimates of reserves and future cash flow as of December 31, 2022 December 31, 2023 and 2021 2022 were prepared using an average price equal to the unweighted arithmetic average of the first day of the month price for each month within the 12-month periods ended December 31, 2022 December 31, 2023 and 2021, 2022, respectively, in accordance with SEC guidelines. As of December 31, 2023, our reserves were based on an SEC average price of $74.70 per Bbl of WTI oil posted and $2.637 per MMBtu of Henry Hub natural gas. As of December 31, 2022, our reserves are were based on an SEC average price of $90.15 per Bbl of WTI oil posted and $6.358 per MMBtu of Henry Hub natural gas. As of December 31, 2021, our reserves are based on an SEC average price of $63.04 per Bbl of WTI oil posted and $3.598 per MMBtu Henry Hub natural gas. Prices are adjusted by local field and lease level differentials and are held constant for life of reserves in accordance with SEC guidelines.

[1] Six Mcf is deemed the equivalent of one Boe.

The standardized measure of discounted future net cash flows relating to the proved oil, natural gas and natural gas liquids NGLs reserves are shown below.

Standardized Measure of Discounted Future Net Cash Flows

December 31,	*December 31,*	2022	2021	2020	*December 31,*	2023	2022	2021
Future cash inflows	Future cash inflows	$9,871,961,000	$4,853,709,000	$2,682,488,655				
Future production costs	Future production costs	(2,751,896,250)	(1,395,437,250)	(821,515,126)				
Future development costs		(647,196,750)	(347,757,000)	(244,323,270)				
Future development costs (1)								
Future income taxes	Future income taxes	(1,142,147,641)	(501,586,949)	(208,645,934)				
Future net cash flows	Future net cash flows	5,330,720,359	2,608,927,801	1,408,004,325				
10% annual discount for estimated timing of cash flows	10% annual discount for estimated timing of cash flows	(3,058,606,841)	(1,471,562,953)	(852,133,072)				
Standardized Measure of Discounted Future Net Cash Flows	**Standardized Measure of Discounted Future Net Cash Flows**	$2,272,113,518	$1,137,364,848	$ 555,871,253				
Standardized Measure of Discounted Future Net Cash Flows								
Standardized Measure of Discounted Future Net Cash Flows								

(1) Future development costs include not only development costs but also future asset retirement costs.

The changes in the standardized measure of discounted future net cash flows relating to the proved oil, natural gas and natural gas liquid reserves are shown below.

Changes in Standardized Measure of Discounted Future Net Cash Flows

		2022	2021	2020			
	2023				2023	2022	2021
Beginning of the year	Beginning of the year	$1,137,364,848	$ 555,871,253	$923,175,051			

Purchase of minerals in place	Purchase of minerals in place	996,313,882	33,688,718	—
Extensions, discoveries and improved recovery	Extensions, discoveries and improved recovery	20,447,842	79,003,885	61,303,074
Development costs incurred during the year	Development costs incurred during the year	67,454,522	17,513,180	29,916,746
Sales of oil and gas produced, net of production costs	Sales of oil and gas produced, net of production costs	(283,588,498)	(154,615,685)	(70,634,853)
Sales of minerals in place	Sales of minerals in place	—	(2,523,746)	—
Accretion of discount	Accretion of discount	133,209,763	63,810,764	92,838,323
Net changes in price and production costs	Net changes in price and production costs	646,819,172	636,884,944	(368,974,767)
Net change in estimated future development costs	Net change in estimated future development costs	(53,253,626)	(44,357,751)	(3,883,985)
Revisions of previous quantity estimates	Revisions of previous quantity estimates	33,583,837	(22,259,508)	(66,213,586)
Changes in estimated timing of cash flows	Changes in estimated timing of cash flows	(119,428,019)	86,845,188	(139,039,115)
Net change in income taxes	Net change in income taxes	(306,810,205)	(112,496,394)	97,384,365
End of the Year	**End of the Year**	$2,272,113,518	$1,137,364,848	$555,871,253
End of the Year				
End of the Year				

Our proved reserves by state as of December 31, 2022 December 31, 2023 are summarized in the table below.

		Oil (Bbl)	Gas (Mcf)	Natural Gas Liquids (NGL) (Bbl)	Total (Boe)	% of Total Proved	Pre-tax PV-10 (In thousands)	Standardized Measure of Discounted Future Net Cash Flows (In thousands)	Future Capital Expenditures (In thousands)
	Oil (Bbl)								
Texas	Texas								
PD									
PD									
PD	PD	54,825,249	105,172,422	15,175,702	87,529,688	63 %	$1,863,175	$ 1,526,269	$ 182,668
PUD	PUD	30,741,939	50,999,854	7,733,492	46,975,407	34 %	853,607	699,254	447,930
Total Proved:	Total Proved:	85,567,188	156,172,276	22,909,194	134,505,095	97 %	$2,716,782	$ 2,225,523	$ 630,598
Total Proved:									
Total Proved:									
New Mexico	New Mexico								
New Mexico									
New Mexico									
PD									
PD									
PD	PD	2,186,888	1,226,628	157,102	2,548,428	2 %	$ 43,506	$ 35,639	$ 1,985
PUD	PUD	950,667	471,545	39,362	1,068,620	1 %	13,369	10,952	14,614
Total Proved:	Total Proved:	3,137,555	1,698,173	196,464	3,617,048	3 %	$ 56,875	$ 46,591	$ 16,599
Total Proved:									
Total Proved:									
Total	Total								
Total									
Total									
PD									
PD									
PD	PD	57,012,137	106,399,050	15,332,804	90,078,116	65 %	$1,906,681	$ 1,561,908	$ 184,653
PUD	PUD	31,692,606	51,471,399	7,772,854	48,044,027	35 %	866,976	710,206	462,544
Total Proved:	Total Proved:	88,704,743	157,870,449	23,105,658	138,122,143	100 %	$2,773,657	$ 2,272,114	$ 647,197
Total Proved:									
Total Proved:									

Oil (Bbl)	Gas (Mcf)	NGL (Bbl)	Total (Boe)	% of Total Proved	Pre-tax PV-10 (In thousands)	Standardized Measure of Discounted Future Net Cash Flows (In thousands)	Future Capital Expenditures (In thousands)

Proved Reserves

As of December 31, 2022 December 31, 2023, we had approximately 138.1 129.8 MMBoe (one million Boe) of proved reserves, consisting of approximately 64% 63% oil, 19% natural gas, and 17% natural gas liquids, 18% NGLs, as summarized in the table above. Our reserve estimates have not been filed with any Federal authority or agency (other than the SEC).

As of December 31, 2022 December 31, 2023, approximately 65% 68% of the proved reserves have been classified as proved developed, or "PD" PD and the remaining 35% 32% are proved undeveloped, or "PUD". PUD.

As of December 31, 2022 December 31, 2023, our total proved reserves had a net pre-tax PV-10 value of approximately $2,773.7 million $1,647.0 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $2,272.1 million $1,399.2 million. Approximately $1,906.7 million $1,262.7 million and $1,561.9 million $1,072.7 million, respectively, of total proved reserves are associated with the PD reserves, which is approximately 69% 77% of the total proved reserves' pre-tax PV-10 value. The remaining $867.0 million $384.4 million and $710.2 million $326.5 million, respectively, are associated with PUD reserves.

Proved Undeveloped Reserves

Our reserve estimates as of December 31, 2023 include approximately 41.6 MMBoe as PUDs. As of December 31, 2022 include, our reserve estimates included approximately 48.0 MMBoe as proved undeveloped reserves (PUD). As reserves. In accordance with our December 31, 2023 year-end independent engineering reserve report, we plan to drill our PUD drilling locations within five years of December 31, 2021, our reserve estimates included approximately 34.4 MMBoe as proved undeveloped reserves. original classification. Below is a description of the changes in our PUD reserves from December 31, 2021 December 31, 2022 to December 31, 2022 December 31, 2023.

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

- *Conversions to developed.* During the year ended December 31, 2022 December 31, 2023, we incurred costs of approximately $87.7 million $90.3 million to convert 26 27 properties from PUD to PD through development. These 26 27 properties produced 709 573 MBoe during the year ended December 31, 2022 December 31, 2023, and have reserves of 8,018 7,068 MBoe as of December 31, 2022 December 31, 2023.

The increase

- *Extensions.* In 2023, extensions of 3.7 MMBoe were primarily the result of the successful operated drilling program and non-operated activity in proved undeveloped the Northwest Shelf and Central Basin Platform.

- *Purchase of minerals in place.* In 2023, we completed the acquisition of Founders oil and gas leases and related property within Ector county that resulted in 3.7 MMBoe in additional reserves.

- *Sales of minerals in place.* In 2023, we sold 1.3 MMBoe from the divestiture of the New Mexico operated assets (81%), and a subset of our assets in Gaines County (19%).

- *Revision of previous estimates.* In 2023, the negative revisions of prior reserves was primarily attributable of 4.9 MMBoe consisted of 0.8 MMBoe (16%) related to the Stronghold Acquisition. changes in price and 4.1 MMBoe (84%) related to changes in performance and other economic factors.

The following table indicates projected reserves that we currently estimate will be converted from proved undeveloped to proved developed, as well as the estimated costs per year involved in such development.

Our PUD reserves are part of a management adopted development plan that schedules PUD reserves to be developed within five years of initial disclosure as proved reserves. As of December 31, 2023, no material amount of proved undeveloped reserves were not scheduled to be converted to proved developed status within five years they were initially disclosed.

Estimated Costs Related to Conversion of Proved Undeveloped Reserves to Proved Developed Reserves

Year	Year	Estimated Oil Reserves Developed (Bbl)	Estimated Gas Reserves Developed (Mcf)	Estimated NGL Reserves Developed (Bbl)	Total Boe	Estimated Development Costs	Year	Estimated Oil Reserves Developed (Bbl)	Estimated Gas Reserves Developed (Mcf)	Estimated NGL Reserves Developed (Bbl)	Total Boe	Estimated Development Costs
2023		7,243,318	9,494,859	1,685,188	10,510,983	$102,822,989						
2024	2024	9,037,309	15,468,017	2,370,819	13,986,131	130,214,495						
2025	2025	8,631,583	17,046,317	2,403,159	13,875,795	125,779,913	2025	8,815,136	7,676,596	1,838,167	11,932,736	126,315,450
2026	2026	5,998,345	9,156,375	1,283,290	8,807,698	89,548,288	2026	4,047,980	15,057,984	2,286,811	8,844,455	73,672,123
2027	2027	782,049	305,832	30,399	863,420	14,178,133	2027	2,737,051	15,128,690	2,105,562	7,364,061	51,012,096
		31,692,604	51,471,400	7,772,855	48,044,027	$462,543,818						
Total												
Total												
Total												

Preparation and Internal Controls Over Reserves Estimates

All the proved oil and natural gas reserves disclosed in this Report are based on reserve estimates determined and prepared by our independent reserve engineers, Cawley, Gillespie & Associates, Inc. ("CGA"), a leader of petroleum property analysis for industry and financial institutions. CGA was founded in 1960 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated February 3, 2023 January 26, 2024, filed as an exhibit to this Annual Report, on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 35 36 years of practical experience in petroleum engineering, with over 33 34 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M

University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

The proved oil and natural gas reserves disclosed in this Annual Report are based on reserve estimates determined and prepared by our independent reserve engineers primarily using decline curve analysis to determine the reserves of individual producing wells. To establish reasonable certainty with respect to our estimated proved reserves, the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using volumetric estimates or performance from analogous wells in the surrounding area. These wells were considered to be analogous based on production performance from the same formation and completions using similar techniques. The technologies and economic data used to estimate our proved reserves include, but are not limited to, well logs, geological maps, seismic data, well test data, production data, historical price and cost information and property ownership interests. This data was reviewed by various levels of management for accuracy before consultation with our independent reserve engineers. This consultation included review of properties, assumptions and available data. Internal reserve estimates were compared to those prepared by independent reserve engineers CGA to test the estimates and conclusions before the reserves were included in this Annual Report. The accuracy of the reserve estimates is dependent on many factors, including the following:

- the quality and quantity of available data and the engineering and geological interpretation of that data;
- estimates regarding the amount and timing of future costs, which could vary considerably from actual costs;
- the accuracy of economic assumptions; and
- the judgment of the personnel preparing the estimates.

Our Executive Vice President of Engineering and Corporate Strategy, Mr. Alex Dyes, is the technical professional primarily responsible for overseeing the preparation of our reserves estimates. He has a Bachelor of Science degree in Petroleum Engineering from the University of Texas with over 16 17 years of practical industry experience, including over 12 13 years of estimating and evaluating reserve information. He has been a member of the Society of Petroleum Engineers since 2013 and his qualifications meet or exceed the Society of Petroleum Engineers' standard requirements to be a professionally qualified Reserve Estimator and Auditor.

We encourage ongoing professional education for our engineers and reservoir analysts on new technologies and industry advancements as well as refresher training on basic skill sets. In order to ensure the reliability of reserves estimates, our Corporate Reserves department follows comprehensive SEC-compliant internal controls and policies to determine, estimate and report proved reserves including:

- confirming that we include reserves estimates for all properties owned and that they are based upon proper working and net revenue interests;
- ensuring the information provided by other departments within the Company, such as Accounting, accounting, land, and operations is accurate;
- communicating, collaborating, and analyzing with technical personnel in our business units;
- comparing and reconciling the internally generated reserves estimates to those prepared by third parties; and
- utilizing experienced reservoir engineers or those under their direct supervision to prepare reserve estimates.

Each quarter, the Corporate Reserves team along with the Executive Vice President of Engineering and Corporate Strategy presents the status of the Company's reserves to senior executives, and subsequently obtains approval of significant changes from key executives. Additionally, our five-year PUD development plan is reviewed and approved annually by the Company's Chief Executive Officer, Chief Financial Officer, Executive Vice President of Operations, and the Executive Vice President of Land, Legal, Human Resources, and Marketing.

The Corporate Reserves department works closely with independent reserve engineers from CGA at each fiscal year end to ensure the integrity, accuracy and timeliness of annual independent reserves estimates. These independently developed reserves estimates are presented to the Audit Committee. In addition to reviewing the independently developed reserve reports, the Audit Committee also periodically meets with the independent reserve engineers that prepare estimates of proved reserves.

Summary of Oil and Natural Gas Properties and Projects

Acreage

The following table summarizes our gross and net developed and undeveloped acreage as of December 31, 2022 December 31, 2023 by region (net acreage is our percentage ownership of gross acreage). Acreage in which our interest is limited to royalty and overriding royalty interests is excluded. excluded, as it is de minimis.

	Developed Acreage	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Gross	Net	Gross	Net	Gross	Net

		Developed Acreage		Undeveloped Acreage		Total Acreage	
		Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	Central Basin Platform	63,912	56,711	3,385	2,668	67,297	59,379
Northwest Shelf	Northwest Shelf	12,572	8,751	16,258	12,405	28,830	21,156
Total	Total	76,484	65,462	19,643	15,073	96,127	80,535

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	64,774	54,959	3,905	2,337	68,679	57,296
Delaware Basin	18,729	18,437	—	—	18,729	18,437
Northwest Shelf	18,270	13,930	18,539	12,512	36,809	26,442
Total	101,773	87,326	22,444	14,849	124,217	102,175

Leases of undeveloped acreage will generally expire at the end of their respective primary terms unless production from such leasehold acreage has been established prior to expiration of such primary term. terms. If production is established on such the acreage, the lease will generally remain in effect until the cessation of production from such the acreage and is referred to in the industry as "Held-By-Production" or "HBP." HBP. Leases of undeveloped acreage may terminate or expire as a result of not meeting certain drilling commitments, if any, or otherwise by not complying with the terms of a lease depending on the specific terms that are negotiated between the lessor and the lessee.

The following table sets forth our gross and net undeveloped acreage, as of December 31, 2022 December 31, 2023, under lease which that will expire over the next three years unless (i) production is established on the lease or within a spacing unit of which the lease is participating, or (ii) the lease is renewed or extended prior to the relevant expiration dates:

		Undeveloped Acreage					
		2024		2025		2026	
		Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	Central Basin Platform	1,800	1,046	1,240	100	720	239
Northwest Shelf	Northwest Shelf	8,475	1,481	8,946	3,496	3,015	454
Total	Total	10,275	2,527	10,186	3,596	3,735	693

	Undeveloped Acreage					
	2023		2024		2025	
	Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	480	234	1,420	1,221	860	49
Delaware Basin	—	—	—	—	—	—
Northwest Shelf	15,240	4,023	11,610	2,021	10,446	3,835
Total	15,720	4,257	13,030	3,242	11,306	3,884

Production History

The following table presents the historical information regarding our produced oil, natural gas and natural gas liquid volumes for the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020: 2021:

		Years ended December 31,				Years ended December 31,		
		2022	2021	2020		2023	2022	2021
	Years ended December 31, 2023							
Oil (Bbls)	**Oil (Bbls)**							
Oil (Bbls)								
Oil (Bbls)								
Central Basin Platform	Central Basin Platform	1,409,211	867,835	958,691				
Delaware Basin		81,936	104,129	159,635				
Central Basin Platform								
Central Basin Platform						2,347,068	1,409,211	867,835
Delaware Basin (2)					Delaware Basin (2)	25,743	81,936	104,129
Northwest Shelf	Northwest Shelf	1,968,693	1,714,976	1,683,202	Northwest Shelf	2,207,131	1,968,693	1,714,976
Total	**Total**	3,459,840	2,686,940	2,801,528	**Total**	4,579,942	3,459,840	2,686,940
Natural Gas (Mcf)								
Natural Gas (Mcf) (1)								
Natural Gas (Mcf) (1)								
Natural Gas (Mcf) (1)								
Central Basin Platform	Central Basin Platform	1,563,808	171,690	268,495				
Delaware Basin		96,516	288,918	468,177				
Central Basin Platform								
Central Basin Platform						3,940,107	1,563,808	171,690
Delaware Basin (2)					Delaware Basin (2)	11,265	96,516	288,918
Northwest Shelf	Northwest Shelf	2,428,318	2,074,580	1,757,830	Northwest Shelf	2,387,786	2,428,318	2,074,580
Total	**Total**	4,088,642	2,535,188	2,494,502	**Total**	6,339,158	4,088,642	2,535,188
Natural Gas Liquids (Bbls) (1)	**Natural Gas Liquids (Bbls)** (1)							
Natural Gas Liquids (Bbls) (1)								
Natural Gas Liquids (Bbls) (1)								
Central Basin Platform	Central Basin Platform	227,996	—	—				
Delaware Basin		3,718	—	—				
Central Basin Platform								
Central Basin Platform						703,818	227,996	—
Delaware Basin (2)					Delaware Basin (2)	2,867	3,718	—
Northwest Shelf	Northwest Shelf	139,615	—	—	Northwest Shelf	270,167	139,615	—
Total	**Total**	371,329	—	—	**Total**	976,852	371,329	—

Total production (Boe)	**Total production (Boe)**							
Total production (Boe)								
Total production (Boe)								
Central Basin Platform	Central Basin Platform	1,897,842	896,087	1,003,440				
Delaware Basin		101,740	152,282	237,665				
Central Basin Platform								
Central Basin Platform						3,707,571	1,897,842	896,087
Delaware Basin (2)					Delaware Basin (2)	30,488	101,740	152,282
Northwest Shelf	Northwest Shelf	2,513,028	2,060,739	1,976,173	Northwest Shelf	2,875,262	2,513,028	2,060,739
Total	**Total**	4,512,610	3,109,108	3,217,278	**Total**	6,613,321	4,512,610	3,109,108
Daily production (Boe/d)	**Daily production (Boe/d)**							
Daily production (Boe/d)								
Daily production (Boe/d)								
Central Basin Platform	Central Basin Platform	5,200	2,455	2,742				
Delaware Basin		279	417	649				
Central Basin Platform								
Central Basin Platform						10,158	5,200	2,455
Delaware Basin (2)					Delaware Basin (2)	84	279	417
Northwest Shelf	Northwest Shelf	6,885	5,646	5,399	Northwest Shelf	7,877	6,885	5,646
Total	**Total**	12,364	8,518	8,790	**Total**	18,119	12,364	8,518

(1) Due to our acquisition of Stronghold's assets, which reported its volumes and revenues on a three-stream basis, beginning July 1, 2022, we began reporting volumes and revenues on a three-stream basis, separately reporting crude oil, natural gas, and natural gas liquid NGL sales. For periods prior to July 1, 2022, sales and reserve volumes, prices, and revenues for natural gas liquids NGLs were presented with natural gas.

(2) The Delaware Basin assets were sold with a closing date of May 11, 2023 and an effective date of March 1, 2023.

Production Prices and Production Costs

The following tables provides historical pricing and costs statistics for the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020. 2021.

	Years ended December 31,		
	2022	2021	2020
Average sales price:			
Oil (per Bbl)			
Central Basin Platform	$ 91.72	$ 67.66	$ 39.64
Delaware Basin	95.97	65.98	35.00
Northwest Shelf	93.44	67.61	38.93
Total	$ 92.80	$ 67.56	$ 38.95

Natural gas (per Mcf)						
Central Basin Platform	$	3.72	$	4.63	$	1.12
Delaware Basin		5.26		4.75		0.54
Northwest Shelf		5.09		6.08		1.91
Total	$	4.57	$	5.83	$	1.57
Natural gas liquids (per Bbl)(1)						
Central Basin Platform	$	20.02	$	—	$	—
Delaware Basin		27.16		—		—
Northwest Shelf		20.25		—		—
Total	$	20.18	$	—	$	—
Total (per Boe)						
Central Basin Platform	$	73.58	$	66.42	$	38.17
Delaware Basin		83.28		54.13		24.57
Northwest Shelf		79.24		62.38		34.86
Total	$	76.95	$	63.14	$	35.13

	Years ended December 31,					
	2023		2022		2021	
Average sales price:						
Oil (per Bbl)	$	76.21	$	92.80	$	67.56
Natural gas (per Mcf) (1)	$	0.05	$	4.57	$	5.83
NGL (per Bbl) (1)	$	11.95	$	20.18	$	—
Total (per Boe)	$	54.60	$	76.95	$	63.14

(1) Due to our acquisition of Stronghold's assets, which reported its volumes and revenues on a three-stream basis, beginning July 1, 2022, we began reporting volumes and revenues on a three-stream basis, separately reporting crude oil, natural gas, and natural gas liquid NGL sales. For periods prior to July 1, 2022, sales and reserve volumes, prices, and revenues for natural gas liquids NGLs were presented with natural gas.

	Years ended December 31,					
	2022		2021		2020	
Average lease operating expenses (per Boe)						
Central Basin Platform	$	13.81	$	15.97	$	15.44
Delaware Basin		44.86		32.75		19.13
Northwest Shelf		6.74		5.34		4.91
Total	$	10.57	$	9.75	$	9.25
Average gathering, transportation and processing costs (per Boe)						
Central Basin Platform	$	—	$	—	$	—
Delaware Basin		—		—		—
Northwest Shelf		0.73		2.10		2.07
Total	$	0.41	$	1.39	$	1.27
Average ad valorem taxes (per Boe)						
Central Basin Platform	$	1.11	$	1.17	$	1.82

Delaware Basin	0.41	0.33	0.50
Northwest Shelf	1.00	0.57	0.60
Total	$ 1.04	$ 0.73	$ 0.97
Average production taxes (per Boe)			
Central Basin Platform	$ 3.64	$ 2.85	$ 1.67
Delaware Basin	3.97	2.45	1.30
Northwest Shelf	3.91	3.01	1.64
Total	$ 3.80	$ 2.93	$ 1.63

	Years ended December 31,		
	2023	2022	2021
Average production costs (per Boe):			
Lease operating expenses	$ 10.61	$ 10.57	$ 9.75
Gathering, transportation and processing costs	$ 0.07	$ 0.41	$ 1.39
Ad valorem taxes	$ 1.02	$ 1.04	$ 0.73
Production taxes	$ 2.74	$ 3.80	$ 2.93

The average oil sales price amounts above are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels "Bbl." Bbls. The average natural gas sales price amounts above are calculated by dividing revenue from natural gas sales by the volume of natural gas sold, in thousand cubic feet "Mcf." Mcf. The average natural gas liquids NGL sales price amounts above are calculated by dividing revenue from natural gas liquids NGL sales by the volume of natural gas liquids NGLs sold, in barrels "Bbl." Bbls. The total average sales price amounts are calculated by dividing total revenues by total volume sold, in Boe. The average production costs above are calculated by dividing production costs by total production in Boe.

Productive Wells

The following table presents our ownership as of December 31, 2022 December 31, 2023 in productive oil and natural gas wells (a net well is our percentage ownership of a gross well). All Over 99.8% of such wells are in the Permian Basin in Texas and New Mexico. Texas.

Oil Wells	Oil Wells		Gas wells		Total Wells	
Gross	Gross	Net	Gross	Net	Gross	Net
	1,033	869	23	19	1,056	888

	Oil Wells		Gas wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
1,023	1,023	847	20	17	1,043	864

Drilling Activity

During 2022, 2023, as operator, we drilled 18.00 a total of 31.00 gross (17.35 (29.75 net) wells. Of this, 14.00 gross (12.75 net) horizontal San Andres wells were in the Northwest Shelf (16.00 (nine 1.0-mile laterals and two five 1.5-mile laterals.) In addition, we drilled 14.00 and 17.00 gross (14.00 (17.00 net) wells were in the Central Basin Platform, of which nine six were horizontal San Andres wells in Andrews County, Texas (four (two 1.0-mile laterals and five four 1.5-mile laterals) and five 11.00 were vertical wells in Crane County, Texas. In addition, we also participated in three five gross (0.33 (0.59 net) non-operated wells of which three were Northwest Shelf and two in the Northwest shelf. Central Basin Platform. These wells were successful and there were no dry wells.

The table below contains information regarding the number of operated wells drilled and and/or participated in during the periods indicated.

	For the year ended December 31,					
	2022		2021		2020	
	Gross	Net	Gross	Net	Gross	Net

	For the year ended December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Exploratory						
Productive						
Productive						

Productive	Productive	—	—	—	—	—	—		—				—	
Dry	Dry	—	—	—	—	—	—	Dry	—				—	
Development	Development													
Productive	Productive	32.00	31.35	11.00	9.91	6.00	5.61							
Productive														
Productive									31.00	29.75	32.00	31.35	11.00	9.91
Dry	Dry	—	—	—	—	—	—	Dry	—				—	
Total	Total													
Productive	Productive	32.00	31.35	11.00	9.91	6.00	5.61							
Productive														
Productive									31.00	29.75	32.00	31.35	11.00	9.91
Dry	Dry	—	—	—	—	—	—	Dry	—				—	

The table below contains information regarding the number of non-operated wells drilled and participated in during the periods indicated.

		For the year ended December 31,												
		2022		2021		2020								
		Gross	Net	Gross	Net	Gross	Net							
	For the year ended December 31,												For the year ended December 31,	
	2023								2023		2022		2021	
	Gross								Gross	Net	Gross	Net	Gross	Net
Exploratory	Exploratory													
Productive														
Productive														
Productive	Productive	—	—	—	—	—	—		—				—	
Dry	Dry	—	—	—	—	—	—	Dry	—				—	
Development	Development													
Productive	Productive	3.00	0.33	2.00	0.23	1.00	0.11							
Productive														
Productive									5.00	0.59	3.00	0.33	2.00	0.23
Dry	Dry	—	—	—	—	—	—	Dry	—				—	
Total	Total													
Productive	Productive	3.00	0.33	2.00	0.23	1.00	0.11							
Productive														
Productive									5.00	0.59	3.00	0.33	2.00	0.23
Dry	Dry	—	—	—	—	—	—	Dry	—				—	

Present Activities

We had no operated wells in the process of being drilled or completed as of December 31, 2022 December 31, 2023.

Cost Information

We conduct our oil and natural gas activities entirely in the United States. As noted in the table under "Production Prices and Production Costs", our average production costs including lease operating expenses, gathering, processing and transportation ("GPT") and ad valorem, per Boe, were $12.02 $11.70 and $11.88 $12.02 for the years ended December 31, 2022 December 31, 2023 and 2021, 2022, respectively, and our average production taxes, per Boe, were $3.80 $2.74 and $2.93 $3.80 for the years ended December 31, 2022 December 31, 2023 and 2021, 2022, respectively. These amounts are calculated by dividing our total production costs or total production taxes by our total volume sold, in Boe.

Costs incurred for property acquisition, exploration and development activities for the years ended December 31, 2022 December 31, 2023, 2021 2022 and 2020 2021 are shown below:

	2022	2021	2020
Stronghold Acquisition	$ 177,823,787	$ —	$ —

Acquisition of proved properties	1,563,703	1,368,437	1,317,313
Divestiture of proved properties	(23,700)	(2,000,000)	—
Development costs	129,332,155	51,302,131	42,457,745
Total costs incurred	$ 308,695,945	$ 50,670,568	$ 43,775,058

	2023	2022	2021
Payments to acquire oil and natural gas properties	$ 82,900,900	$ 179,387,490	$ 1,368,437
Payments to explore oil and natural gas properties	—	—	—
Payments to develop oil and natural gas properties	152,559,314	129,332,155	51,302,131
Total costs incurred	$ 235,460,214	$ 308,719,645	$ 52,670,568

Other Properties and Commitments

Effective January 1, 2021, the Company moved its corporate headquarters to The Woodlands, Texas. Prior to this, our principal offices were in Midland, Texas. Those offices now serve as an operations office. Our office space lease in Tulsa, Oklahoma was terminated as of March 31, 2021.

Item 3: Legal Proceedings

The Company is a defendant in a lawsuit in Harris County District Court, Houston, Texas, styled EPUS Permian Assets, LLC, v. Ring Energy, Inc., that was filed in July 2021. The plaintiff, EPUS Permian Assets, LLC, claims breach of contract, money had and received by fraudulent inducement, unjust enrichment and constructive trust. The plaintiff is requesting its forfeited deposit of $5,500,000 in connection with a proposed property sale by the Company plus related damages, and attorneys' fees and costs. The action relates to a proposed property sale by the Company to the plaintiff, which was extended by the Company on several occasions with the plaintiff ultimately failing to perform on the agreement and the Company keeping the deposit. The Company believes that the claims by the plaintiff are entirely without merit and is conducting a vigorous defense and counterclaim. The Company has filed an answer and a counterclaim denying the allegations and asserting affirmative defenses that would bar or substantially limit the plaintiff's claims, asserting breach of contract and requesting a declaratory judgment and attorneys' fees and costs. The parties have taken begun taking depositions and are conducting discovery.

Item 4: Mine Safety Disclosures

Not applicable.

PART II

Item 5: Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for our Common Stock

Our common stock is listed on the NYSE American under the trading symbol "REI."

Performance Graph

In 2022, we chose to compare our cumulative 5-year total return attained by stockholders on our common stock relative to the cumulative total returns of the S&P Oil and Gas Exploration and Production Select Industry Index ("SPSIOP"), instead of a peer group ("Peer Group"). If a company selects a different index or peer group from that used in the immediately preceding fiscal year, the company's stock performance must be compared with both the newly-selected index or peer group and the index used in the immediately preceding year. Accordingly, the The following graph reflects a comparison of the cumulative total stockholder return of our common stock relative to the cumulative total returns of the S&P 500 Index the SPSIOP and the 2021 Peer Group. S&P Oil and Gas Exploration and Production Select Industry Index ("SPSIOP"). The graph assumes the investment of $100 on December 31, 2017 December 31, 2018 in our common stock and each index and the reinvestment of all dividends, if any. This table is not intended to forecast future performance of our common stock.

1223

* In 2021, the peer group consisted of: Abraxas Petroleum Corporation, Amplify Energy Corp., Civitas Resources, Inc., Earthstone Energy, Inc., Vital Energy, Inc. (formerly Laredo Petroleum, Inc.), Ranger Oil Corporation, SilverBow Resources, Inc., and W&T Offshore, Inc., each of which is in the oil and natural gas exploration and production industry.

The performance graph above is furnished and not filed for purposes of Section 18 of the Exchange Act and will not be incorporated by reference into any registration statement filed under the Securities Act unless specifically identified therein as being incorporated by reference. The performance graph is not solicitation material subject to Regulation 14A of the Exchange Act.

Record Holders

As of March 9, 2023 March 7, 2024, there were approximately 76 84 holders of record of our common stock. This is the number of record holders in the records of the our transfer agent. It does not include holders of shares via brokerage accounts.

Dividend Policy

We do not currently anticipate paying any cash dividends on our common stock. We currently intend to retain future earnings, if any, to pay down debt and finance the expansion of our business. Our future dividend policy is within the discretion of our Board of Directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, our credit facility contains provisions limiting our ability to pay dividends until unless certain conditions are met.

Recent Sales of Unregistered Securities and Use of Proceeds from Registered Securities

The information required by this item was disclosed and reported under Item 3.02, Unregistered Sales of Equity Securities, of our Form 8-K dated August 30, 2022, filed with the SEC on September 6, 2022, which disclosure is incorporated herein by reference.

Issuer Repurchases

We did not make any repurchases of our equity securities during the year ended December 31, 2022 December 31, 2023.

Item 6: Reserved

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

The following discussion and analysis should be read in conjunction with our accompanying financial statements and the notes to those financial statements included elsewhere in this Annual Report. The following discussion includes forward-looking statements that reflect our plans, estimates, and beliefs and our actual results could differ materially from those discussed in these forward-looking statements as a result of many factors, including those discussed under "Risk Factors," "Forward Looking Statements" Statements," and elsewhere in this Annual Report.

Overview

Ring Energy, Inc. (the "Company," "Ring," "we," "us," "our" and similar terms) is a growth oriented independent oil and natural gas exploration and production company based in The Woodlands, Texas and is engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas. Our primary drilling operations target the oil and liquids rich producing formations in the Northwest Shelf and the Central Basin Platform, and the Delaware Basin all of which are part of in the Permian Basin. Basin in Texas.

Business Description and Plan of Operation

The Company is focused on balancing the need to reduce long-term debt and further developing our oil and gas properties to maintain or grow our annual production. We intend to achieve both through proper allocation of cash flow generated by our operations and potentially through the sale of non-core assets. We intend to continue evaluating potential transactions to acquire strategic producing assets with attractive acreage positions that can provide competitive returns for our shareholders.

- ***Growing production and reserves by developing our oil-rich resource base through conventional and horizontal drilling.*** In an effort to maximize its value and resources potential, Ring intends to drill and develop its acreage base in both the Northwest Shelf and Central Basin Platform assets, allowing Ring to execute on its plan of operating within its generated cash flow.

2022• ***Reduction of long-term debt and deleveraging of asset.*** Ring intends to reduce its long-term debt primarily through the use of excess cash flow and potentially through the sale of non-core assets. The Company believes that with its attractive field level margins, it is positioned to maximize the value of its assets and deleverage its balance sheet. The Company also believes through potential accretive acquisitions and strategic asset dispositions, it can accelerate the strengthening of its balance sheet. During the three months ended December 31, 2023, the Company made net paydowns of $3 million on its revolving line of credit, resulting in the outstanding long-term debt balance of $425 million.

- ***Employ industry leading drilling and completion techniques***. Ring's executive team intends to utilize new and innovative technological advancements for completion optimization, comprehensive geological evaluation, and reservoir engineering analysis to generate value and to build future development opportunities. These technological advancements have led to a low-cost structure that helps maximize the returns generated by our drilling programs.

- ***Pursue strategic acquisitions with attractive upside potential.*** Ring has a history of acquiring leasehold positions that it believes to have additional resource potential that meet its targeted returns on invested capital and comparable to its existing inventory of drilling locations. We pursue an acquisition strategy designed to increase reserves at attractive finding costs and complement existing core properties. Management intends to continue to pursue strategic acquisitions and structure the potential transactions financially, so they improve our balance sheet metrics and are accretive to shareholders. Our executive team, with its extensive experience in the Permian Basin, has many relationships with operators and service providers in the region.

2023 Developments and Highlights

Stronghold Acquisition

On July 1, 2022, Ring, as buyer, and Stronghold Energy II Operating, LLC, a Delaware limited liability company (“Stronghold OpCo”) and Stronghold Energy II Royalties, LP, a Delaware limited partnership (“Stronghold RoyaltyCo”, together with Stronghold OpCo, collectively, “Stronghold”), as seller, entered into a purchase and sale agreement (the “Purchase Agreement”). Pursuant to the Purchase Agreement, Ring acquired (the “Stronghold Acquisition”) interests in oil and gas leases and related property of Stronghold consisting of approximately 37,000 net acres located in the Central Basin Platform of the Texas Permian Basin. On August 31, 2022, Ring completed the Stronghold Acquisition.

The fair value of consideration paid to Stronghold was approximately $394.0 million, of which $165.9 million, net of customary purchase price adjustments, was paid in cash at closing, $15.0 million was paid in cash after the six-month anniversary of the closing date of the Stronghold Acquisition. Shortly after closing, approximately $4.5 million was paid for inventory and vehicles and approximately $1.8 million was paid for August oil derivative settlements for certain novated hedges. The cash portion of the consideration was funded primarily from borrowings under a new fully committed revolving credit facility (the “Credit Facility”) underwritten by Truist Securities, Citizens Bank, N.A., KeyBanc Capital Markets Inc., and Mizuho Bank, Ltd. The borrowing base of the $1.0 billion Credit Facility was increased from $350.0 million to $600.0 million at the closing of the Stronghold Acquisition. The remaining consideration consisted of 21,339,986 shares of Ring common stock and 153,176 shares of newly created Series A Convertible Preferred Stock, par value $0.001 (“Preferred Stock”) which was converted into 42,548,892 shares of common stock on October 27, 2022. Please see "Note 12 - STOCKHOLDERS' EQUITY" for further discussion. In addition, Ring assumed $24.8 million of derivative liabilities,$1.7 million of items in suspense and $14.5 million in asset retirement obligations.

Drilling, Completion, and Recompletion

In the first quarter of 2022, we contracted a rig for our horizontal drilling program and began operations on January 31st. We drilled and completed three 1-mile horizontal wells and one 1.5-mile horizontal well 2023, in the Central Basin Platform. We then moved the rig to the Northwest Shelf, and drilled two 1-mile horizontal wells. All wells drilled in the first quarter had a working interest of 100%.

In the second quarter of 2022, we drilled a total of nine wells, completed seven wells, and began the completion process on four wells, all in the Northwest Shelf. The first wells completed were the two 1-mile horizontal wells, which were drilled in the first quarter. Next, we Company drilled and completed two 1-mile horizontal wells (each with a working interest of

100%), and two 1.5-mile horizontal wells (one with a working interest of approximately 98.7% 99.8% and one 1-mile horizontal well the other with a working interest of approximately 75.4%). We also Next, in its Crane County acreage within the Central Basin Platform, the Company drilled and began the completion process on an additional four 1-mile horizontal wells. Two of the completed three vertical wells have (each with a working interest of 100%, one has) and performed six vertical well recompletions (each with a working interest of approximately 87.9%, and the fourth has a working interest of 75% 100%).

In the third second quarter of 2022, we completed and placed on production the four aforementioned 1-mile horizontal wells 2023, in the Northwest Shelf, which were drilled in the second quarter. Next, we Company drilled and completed two 1.5-mile horizontal wells (one with a working interest of 100% and one 1-mile horizontal well in the Central Basin Platform other with a working interest of approximately 75.4%) and two 1-mile horizontal wells in the Northwest Shelf, each (both with a working interest of 100% approximately 91.1%). Additionally, in its Crane County acreage within the Central Basin Platform, the Company drilled and completed two vertical wells (each with a working interest of 100%) and performed three vertical well recompletions (each with a working interest of 100%).

During the last month third quarter of 2023, the quarter, we Company drilled and completed two 1-mile horizontal wells (one with a working interest of 100% and the other with a working interest of 75%) in the Northwest Shelf, and three 1.5-mile horizontal wells (each with a working interest of 100%) in the Central Basin Platform. Additionally, in its Crane County acreage within the Central Basin Platform, the Company drilled and completed three vertical wells (each with a working interest of 100%). Lastly, the Company drilled and began the completion process on three 1-mile horizontal wells in the Northwest Shelf two (each with a working interest of 99.7% and one with a working interest of 100%). In total, during the third quarter of 2022, we drilled eight, completed nine, and began the completion process on three horizontal wells. With the addition of the Stronghold Acquisition assets in the Central Basin Platform, we also performed three vertical well re-completions.

In the fourth quarter of 2022, we 2023, the Company completed and placed on production the three aforementioned 1-mile horizontal wells in the Northwest Shelf. Next, we Additionally, the Company drilled and completed one saltwater disposal (SWD) well in the Northwest Shelf (with a working interest of 100%), and completed the 2023 horizontal drilling program with one 1.5-mile horizontal well in the Northwest Shelf (with a working interest of approximately 97.7%), as well as two 1-mile horizontal wells and one 1.5-mile horizontal well (each with a working interest of 100%, also in the Northwest Shelf. To complete the 2022 horizontal drilling program, we drilled and completed two 1.5-mile horizontal wells) in the Central Basin Platform. In addition to the horizontal wells, we performed nine more vertical well re-completions and drilled and completed five new vertical wells on the Stronghold Acquisition assets located in its Crane County Texas, of acreage within the Central Basin Platform, all the Company drilled and completed three vertical wells (each with a working interest of 100%).

In summary, for 2022, we 2023, the Company drilled and completed 27 20 horizontal wells, and 5 11 vertical wells, along with 12 and 1 SWD well. In addition, the Company performed 9 vertical well re-completions on the Stronghold Acquisition assets. recompletions. The table below sets forth our drilling and completion activities for 2022 2023 by quarter, and full year total through December 31, 2022 December 31, 2023.

Quarter	Area	Wells Drilled	Wells Completed	Recompletions
1Q 2022	Central Basin Platform (Horizontal)	4	4	—
	Central Basin Platform (Vertical)	—	—	—
	Northwest Shelf	2	—	—

2Q 2022	Central Basin Platform (Horizontal)	—	—	—
	Central Basin Platform (Vertical)	—	—	—
	Northwest Shelf	9	7	—
3Q 2022	Central Basin Platform (Horizontal)	3	3	—
	Central Basin Platform (Vertical)	—	—	3
	Northwest Shelf	5	6	—
4Q 2022	Central Basin Platform (Horizontal)	2	2	—
	Central Basin Platform (Vertical)	5	5	9
	Northwest Shelf	2	5	—

Quarter	Area	Wells Drilled	Wells Completed	Recompletions
1Q 2023	Northwest Shelf (Horizontal)	4	4	—
	Central Basin Platform (Horizontal)	—	—	—
	Central Basin Platform (Vertical)	3	3	6
	Total	7	7	6
2Q 2023	Northwest Shelf (Horizontal)	4	4	—
	Central Basin Platform (Horizontal)	—	—	—
	Central Basin Platform (Vertical)	2	2	3
	Total	6	6	3
3Q 2023	Northwest Shelf (Horizontal)	5	2	—
	Central Basin Platform (Horizontal)	3	3	—
	Central Basin Platform (Vertical)	3	3	—
	Total	11	8	—
4Q 2023	Northwest Shelf (Horizontal)	1	4	—
	Central Basin Platform (Horizontal)	3	3	—
	Central Basin Platform (Vertical)	3	3	—
	Total (1)	7	10	—
FY 2023	Northwest Shelf (Horizontal)	14	14	—
	Central Basin Platform (Horizontal)	6	6	—
	Central Basin Platform (Vertical)	11	11	9
	Total (1)	31	31	9

(1) Fourth quarter total and full year total do not include one SWD well completed in the Northwest Shelf.

Market Conditions and Commodity Prices

Our financial results depend on many factors, particularly the price of crude oil and natural gas 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 both domestically and world wide, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other many factors. As a result, we cannot accurately predict future commodity prices, and therefore, we cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our drilling program, production volumes, or revenues.

The improvement of Average oil and natural gas prices experienced in received through 2022 continues and 2023 continued to demonstrate commodity price volatility and we believe oil and natural gas prices will continue to be volatile for the foreseeable future. The ability to find and develop sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success.

Natural Gas Takeaway Capacity

The Permian Basin has been experiencing a lack of sufficient pipeline transportation that is connected to markets that are purchasing the natural gas produced. This has resulted in negative natural gas prices at times, whereby the seller is actually paying the purchaser to take the gas. If these depressed or inverted natural gas prices continue in the region, our natural gas revenues will continue to be negatively impacted.

Inflation

Inflation has increased costs associated with our capital program and production operations. We have experienced increases in the costs of many of the materials, supplies, equipment and services used in our operations and we expect inflation to continue based on current economic circumstances. In addition, the attempts to reduce inflation by the U.S. Federal Reserve have resulted in increased interest rates on debt, contributed to debt and equity market volatility and increased substantially our interest expense. We continue to closely monitor costs and take all reasonable steps to mitigate the inflationary effect on our cost structure and also work to enhance our efficiency to minimize additional cost increases where possible.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

For the years ended December 31,	For the years ended December 31,	2022	2021	2020	For the years ended December 31,	2023	2022	2021
Net production:	Net production:							
Net production:								
Net production:								
Oil (Bbls)								
Oil (Bbls)								
Oil (Bbls)	Oil (Bbls)	3,459,840	2,686,940	2,801,528				
Natural gas (Mcf)	Natural gas (Mcf)	4,088,642	2,535,188	2,494,502				
Natural gas liquids (Bbls)	Natural gas liquids (Bbls)	371,329	—	—				
Net sales:	Net sales:							
Net sales:								
Net sales:								
Oil								
Oil								
Oil	Oil	$321,062,672	$181,533,093	$109,113,557				
Natural gas	Natural gas	18,693,631	14,772,873	3,911,581				
Natural gas liquids	Natural gas liquids	7,493,234	—	—				
Average sales price:	Average sales price:							
Average sales price:								
Average sales price:								
Oil (per Bbl)								
Oil (per Bbl)								
Oil (per Bbl)	Oil (per Bbl)	$ 92.80	$ 67.56	$ 38.95				

Natural gas (per Mcf)	Natural gas (per Mcf)	4.57	5.83	1.57
Natural gas liquids (Bbl)	Natural gas liquids (Bbl)	20.18	—	—
Production costs and expenses:	Production costs and expenses:			
Production costs and expenses:				
Production costs and expenses:				
Lease operating expenses				
Lease operating expenses				
Lease operating expenses	Lease operating expenses	$ 47,695,351	$ 30,312,399	$ 29,753,413
Gathering, transportation and processing costs	Gathering, transportation and processing costs	1,830,024	4,333,232	4,090,238
Ad valorem taxes	Ad valorem taxes	4,670,617	2,276,463	3,125,222
Production taxes		17,125,982	9,123,420	5,228,090
Oil and natural gas production taxes				
Other costs and operating expenses:	Other costs and operating expenses:			
Depreciation, depletion and amortization expense		$ 55,740,767	$ 37,167,967	$ 43,010,660
Ceiling test impairment		—	—	277,501,943
Other costs and operating expenses:				
Other costs and operating expenses:				
Depreciation, depletion and amortization				
Depreciation, depletion and amortization				
Depreciation, depletion and amortization				
Asset retirement obligation accretion				
Asset retirement obligation accretion				
Asset retirement obligation accretion	Asset retirement obligation accretion	983,432	744,045	906,616
Operating lease expense	Operating lease expense	363,908	523,487	1,196,372
General and administrative expense (excluding stock-based compensation)		19,933,092	13,649,782	11,509,888

Stock-based compensation expense	7,162,231	2,418,323	5,364,162
General and administrative expense ("G&A")			
Share-based compensation			
G&A excluding share-based compensation			
Other income (expense): Other income (expense):			
Other income (expense):			
Other income (expense):			
Interest income			
Interest income			
Interest income			
Interest (expense) Interest (expense)	$ (23,167,729)	$ (14,490,474)	$ (17,617,614)
Gain (loss) on derivative contracts Gain (loss) on derivative contracts	(21,532,659)	(77,853,141)	21,366,068
Deposit forfeiture income	—	—	5,500,000
Loss on disposal of assets			
Other income			
Provision for Income Taxes			
Provision for Income Taxes			
Provision for Income Taxes			

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

Oil sales. Oil sales increased approximately $28.0 million to $349.0 million in 2023 from $321.1 million in 2022. The oil sales increased by a volume variance of approximately $103.9 million from a significant increase in sales volumes to 4,579,942 barrels of oil in 2023from 3,459,840 barrels of oil in 2022, with approximately 19% of the increase in oil

volumes related to the Founders Acquisition. Other impacts to revenue volumes include organic growth from workovers, new drills, and other capital expenditures, offset by divestitures completed. The volume variance was offset by a negative price variance of approximately $76.0 million from a decrease in the average realized per barrel oil price to $76.21 in 2023 from $92.80 in 2022.

Natural gas sales. Natural gas sales decreased approximately $18.4 million to $0.3 million in 2023 from $18.7 million in 2022. The natural gas sales decreased by a negative price variance of approximately $28.6 million, as the average realized per Mcf gas price decreased to $0.05 in 2023 from $4.57 in 2022. The significant reduction in realized natural gas prices was driven by a lower market index price. In 2023, the average gross realized price for natural gas was $1.67 per Mcf, and the average fees per Mcf were $(1.62), bringing the net average price to $0.05 per Mcf. In 2022, the average gross realized price for natural gas was $6.32 per Mcf, and the average fees per Mcf were $(1.75), bringing the net average price to $4.57 per Mcf. This was partially offset by a volume variance of approximately $10.3 million as the volume increased to 6,339,158 Mcf in 2023 from 4,088,642 Mcf in 2022.

NGL sales. NGL sales increased approximately $4.2 million to $11.7 million in 2023 from $7.5 million in 2022. NGL sales had a volume variance of approximately $12.2 million, as volumes were 976,852 barrels of NGLs in 2023 compared to 371,329 barrels in 2022. The volumes increase was primarily due to the Company's change in reporting presentation for its natural gas productions, which were presented on a three-stream basis basis beginning July 1, 2022. Offsetting this increase to sales was a negative price variance of approximately $8.0 million, as the average realized price per barrel of NGLs was $11.95 in 2023 compared to $20.18 in 2022.

Lease operating expenses. Our total lease operating expenses (“LOE”) increased approximately $22.5 million to $70.2 million in 2023 from $47.7 million in 2022 and increased slightly on a Boe basis to $10.61 in 2023 from $10.57 in 2022. These per Boe amounts are calculated by dividing our total LOE by our total volume sold, in Boe. LOE increased primarily due to a 47% increase in production of 2,100,711 Boe year-over-year. Specifically, the following cost increases accounted for the majority of the increase in LOE:

$7.5 million in LOE workover costs, $4.2 million in salaries and wages, $2.5 million in electrical/utilities costs, $1.6 million in equipment rental/services $1.3 million in supplies/materials, $1.2 million in contract services, and $1.0 million in chemicals/treating costs.

Gathering, transportation and processing costs.Our total gathering, transportation and processing costs ("GTP") decreased by $1,372,451 to $457,573 in 2023 from $1,830,024 in 2022 and decreased slightly on a Boe basis to $0.07 in 2023 from $0.41 in 2022. In May 2022, a contract update with one of our largest natural gas processors altered the point of control of gas resulting in a change to the recording of those fees from expense to a netted reduction to revenues. There remains only one contract with a natural gas processing entity in place where point of control of gas dictates requiring the fees be recorded as an expense.

Ad valorem taxes. Our total ad valorem taxes increased approximately $2.1 million to $6.8 million in 2023 from $4.7 million in 2022 and decreased on a Boe basis to $1.02 in 2023 from $1.04 in 2022 . Ad valorem taxes increased due to a full year of taxes for the properties within counties acquired in the Stronghold Acquisition (i.e. Crane County) as well as a partial year of taxes for properties within Ector County, acquired in the Founders Acquisition. Additional increases were primarily in Yoakum County and Andrews County.

Oil and natural gas production taxes.Oil and natural gas production taxes as a percentage of oil and natural gas sales increased to 5.02% in 2023 from 4.93% during 2022. Overall, the percentage was consistent year over year.

Depreciation, depletion and amortization.Our depreciation, depletion and amortization expense increased approximately $32.9 million to $88.6 million in 2023 from $55.7 million in 2022 due to an increase in our total estimated costs of property, resulting in a higher depletion expense per unit, as well as an increase of 2,100,711 in Boe produced. Our average depreciation, depletion and amortization per Boe increased to $13.40 per Boe during 2023 from $12.35 per Boe during 2022.

Asset retirement obligation accretion. Our asset retirement obligation ("ARO") accretion increased by $442,254 to $1,425,686 in 2023 from $983,432 in 2022. This was due to a full year of accretion on the assets acquired in the Stronghold Acquisition, a partial year of accretion on the assets acquired in the Founders Acquisition, and new wells drilled during 2023, offset by wells sold during 2023.

Operating lease expense.Our operating lease expense increased by $177,893 to $541,801 in 2023 from $363,908 in 2022 due to a full year of the Midland office lease additional space, which was amended effective October 1, 2022, as

well as a quarter's impact of The Woodlands office lease additional space, which was substantially completed on September 27, 2023.

General and administrative expenses (including share-based compensation).General and administrative expenses increased approximately $2.1 million to $29.2 million in 2023 from $27.1 million in 2022. The increase was primarily related to a $2.2 million increase in salaries, wages, and bonuses, a $1.7 million increase in share-based compensation, $0.6 million in additional legal fees, $0.5 million in higher software costs, $0.1 million in engineering costs, and $0.1 million in accounting, tax, and audit fees. These cost increases were partially offset by a reduction of $2.0 million in transaction costs and a $0.6 million reduction in G&A costs from the Employee Retention Tax Credit.

Interest income. Interest income increased by $257,151 to $257,155 in 2023 from $4 in 2022. The 2023 interest income consisted of $226,315 from depositing excess cash balances in bank sweep accounts beginning in May 2023, $29,042 from interest earned on the Employee Retention Tax Credit, and $1,798 from interest earned on the escrow deposit made for the Founders Acquisition.

Interest expense. Interest expense increased approximately $20.8 million to $43.9 million in 2023 from $23.2 million in 2022. The increase was the result of a combination of higher interest rates, with a weighted average interest rate of 8.8% in 2023 and 5.8% in 2022, and having higher amounts outstanding on our credit facility throughout 2023, with a weighted average daily debt of approximately $422.5 million in 2023 compared to approximately $344.0 million in 2022.

Gain (loss) on derivative contracts.During 2023, the Company incurred a gain on derivative contracts of approximately $2.8 million. During 2022, the Company recorded a loss on derivative contracts of approximately $21.5 million. For the derivative contract settlements, the Company recorded a realized loss of $9.1 million during 2023 and a realized loss of $62.5 million during 2022. The decrease of $53.4 million in the realized loss was $50.5 million from realized oil derivative settlements and $2.9 million from realized natural gas derivative settlements. For the marked-to-market contracts, the Company recorded an unrealized gain of $11.9 million during 2023 and an unrealized gain of $41.0 million during 2022. This change of $29.1 million in unrealized derivatives was from $31.1 million in favorable derivative portfolio changes and futures pricing for marked-to-market oil derivative contracts, offset by $1.9 million unfavorable changes to the marked-to-market natural gas derivative contract balance.

Loss on disposal of assets. During 2023, the Company recognized a loss on disposal of assets of $87,128 from selling multiple company owned vehicles.

Other income. During 2023, the Company's other income of $198,935 primarily resulted from the termination of The Woodlands office operating lease as of May 31, 2023, along with a bank rebate related to the use of a vendor payment program.

Provision for income taxes.The provision for income taxes changed to a provision of $125,242 for 2023 from a provision of $8,408,724 for 2022. The current year change in the Company's federal tax provision was the result of a full valuation allowance release on federal taxes in 2023 with state tax activity recognized.

Net income.The Company achieved net income of $104,864,641 in 2023 compared to net income of $138,635,025 in 2022 compared. The decrease in net income was due to increased LOE costs, depletion, depreciation, and amortization costs, and interest expense and lower natural gas revenues. This was offset by increased oil and NGL revenues in addition to a more favorable derivative contract portfolio in comparison with the year-end commodity futures prices.

Year Ended December 31, 2022 Compared to Year Ended December 31, 2021

Oil sales. Oil sales increased approximately $139.5 million from $181.5 million in 2021 to $321.1 million in 2022. The oil sales increase was the result of 2022 due to an increase in the average realized per barrel oil price from $67.56 in 2021 to

$92.80 $92.80 in 2022 and an increase in sales volume from 2,686,940 barrels of oil in 2021 to 3,459,840 barrels of oil in 2022. The increased average realized per barrel oil price was a result of the significantly higher oil price during the first eight months of 2022. The increased sales volumes were a direct result of assets acquired in the Stronghold Acquisition, which resulted in higher volumes for the last four months of 2022, as well as organic growth from capital expenditures that were $78.0 million greater in 2022 than in 2021.

Natural gas sales. Natural gas sales increased approximately $3.9 million from $14.8 million in 2021 to $18.7 million in 2022. The natural gas sales volume increased from 2,535,188 Mcf in 2021 to 4,088,642 Mcf in 2022 and the average realized per Mcf gas price decreased from $5.83 in 2021 to $4.57 in 2022. The sales volume increase was due to

the aforementioned increase in capital expenditures as well as the Stronghold Acquisition, which closed August 31, 2022. The price decrease was driven by the Company's change in reporting presentation from two-stream (oil and natural gas) to three-stream (oil, natural gas and natural gas liquids) NGLs) beginning July 1, 2022.

Natural gas liquids NGL sales.*Natural gas liquids*NGL sales increased approximately $7.5 million from $0.0 million in 2021 to $7.5 million in 2022. NGL sales volumes in were 371,329 barrels of NGLs compared to zero barrels in 2021, due to the Company’s change in reporting presentation for its natural gas products, which are were presented on a three-stream basis beginning July 1, 2022. The average realized price per barrel of NGLs was $20.18 in 2022.

Lease operating expenses. Our total lease operating expenses (“LOE”) LOE increased from $30,312,399 in 2021 to $47,695,351 in 2022 and increased on a Boe basis from $9.75 in 2021 to $10.57 in 2022. These per Boe amounts are calculated by dividing our total lease operating expenses LOE by our total volume sold, in Boe. LOE increased primarily due to a 45% increase in production of 1,403,502 Boe year-over-year, as well as increased costs for goods and services due to increased Permian activity.

Gathering, transportation and processing costs. Our total gathering, transportation and processing costs (“GTP”) GTP decreased from $4,333,232 in 2021 to $1,830,024 in 2022 and decreased on a Boe basis from $1.39 in 2021 to $0.41 in 2022. GTP costs decreased due to costs classified as a reduction to oil and natural gas sales revenues, due to a natural gas processing entity beginning to take control of transportation at the wellhead beginning May 1, 2022.

Ad valorem taxes. Our total ad valorem taxes increased from $2,276,463 in 2021 to $4,670,617 in 2022 and increased on a Boe basis from $0.73 in 2021 to $1.04 in 2022. Ad valorem taxes increased primarily due to the increase in taxed commodity prices from the prior year, as well as $783,159 for the properties acquired in the Stronghold Acquisition.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales were 4.65% during 2021 and increased to 4.93% in 2022. Overall, the percentage was consistent year over year, with a slight increase due to proportionately higher gas revenues which are taxed at a higher rate. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states (currently only Texas and New Mexico), and on the possibility that any state may raise its production tax rates.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased from $37,167,967 in 2021 to $55,740,767 in 2022 due to an increase in our total estimated costs of property as well as an increase of 1,403,502 in Boe produced. Our average depreciation, depletion and amortization per Boe increased from $11.95 per Boe during 2021 to $12.35 per Boe during 2022. These per Boe amounts are calculated by dividing our total depreciation, depletion and amortization expense by our total Boe volumes sold.

Asset retirement obligation accretion. Our asset retirement obligation (“ARO”) ARO accretion increased from $744,045 in 2021 to $983,432 in 2022. This was a result of the 32 additional wells added from 2022 drilling activities as well as ARO accretion associated with the properties acquired in the Stronghold Acquisition, offset by wells plugged and abandoned during the year. 2022.

Operating lease expense. Our operating lease expense decreased from $523,487 in 2021 to $363,908 in 2022 due to the month to month leases for office equipment and compressors used in operations on which the Company had previously elected to apply ASU 2016-02. The office equipment and compressors are not subject to ASU 2016-02 based on the agreement and nature of use. The costs have been recorded as short-term lease costs and amounts included in lease operating expenses beginning in the second quarter of 2021.

General and administrative expenses (including share-based compensation). General and administrative expenses increased from $16,068,105 in 2021 to $27,095,323 in 2022. The increase was primarily related to a $4,743,908 increase in share-based compensation, as well as increases in salaries and bonuses, all attributed to a nearly doubled headcount from 2021 to 2022 to support our growth. Other cost increases include software maintenance, rent, insurance, and environmental sustainability. The 2022 expenses also included non-recurring acquisition-related costs of $2.1 million.

Interest expense. Interest expense increased from $14,490,474 in 2021 to $23,167,729 in 2022. The increase was the result of a combination of higher interest rates during the second half of 2022, with a weighted average interest rate of 5.8% in 2022 and 4.4% in 2021, and having higher amounts outstanding on our credit facility throughout 2022, with a weighted average daily debt of approximately $308.7 million in 2021 compared to approximately $344.0 million in 2022, particularly due to the additional debt incurred for the Stronghold Acquisition.

Gain (loss) on derivative contracts. During 2022, the Company incurred a loss on derivative contracts of $21,532,659. During 2021, the Company recorded a loss on derivative contracts of $77,853,141. For the derivative contract settlements, the Company recorded a realized loss of $52,768,154 during 2021 and a realized loss of $62,525,954 during 2022, The increase of $9,757,800 in the realized loss was a result of the rise of crude oil prices during 2022, which was above the fixed prices of the derivative contracts. For the marked-to-market contracts, the Company recorded an unrealized gain of $40,993,295 during 2022 and an unrealized loss of $25,084,987 during 2021. This change in unrealized derivatives was due to the roll off of unfavorable contracts during 2022, as well as the Company's purchase of more favorable contracts during 2022.

Benefit from (Provision for) Provision for income taxes. The benefit from (provision for) provision for income taxes changed from a provision of $90,342 for 2021 to a provision of $8,408,724 for 2022. The current year federal tax expense was the result of certain existing deferred tax assets that will not be offset by existing deferred tax liabilities as a result of the 80% limitation on the utilization of net operating losses incurred after 2017.

Net income (loss). The Company had a achieved net income of $3,322,892 in 2021 compared to net income of $138,635,025 in 2022. The increase in net income was due primarily to the increase in oil, natural gas, and natural gas liquids NGL revenues, as well as the reduction in derivative contract losses, offset by increases in lease operating expenses, depletion, general and administrative expenses, and interest expense.

Year Ended December 31, 2021 Compared to Year Ended December 31, 2020

Oil and natural gas sales. Oil and natural gas sales revenue increased from 2020 levels by approximately $83.3 million to $196.3 million in 2021. Oil sales increased approximately $72.4 million and natural gas sales increased approximately $10.9 million. The oil sales increase was the result of an increase in the average realized per barrel oil price from $38.95 in 2020 to $67.56 in 2021, slightly offset by a decrease in sales volume from 2,801,528 barrels of oil in 2020 to 2,686,940 barrels of oil in 2021. These per barrel amounts are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels. Despite the few months of shut in or curtailed production due to oil price destabilizing from the COVID-19 pandemic, volumes in 2020 significantly benefited from the large amount of capital expenditures incurred in the previous year. Likewise, the lower capital expenditures in 2020 resulted in a negative impact to 2021 volumes due to natural well declines. Capital expenditures in 2021 helped offset declines, but not enough to overcome the full impact from the reduced capital expenditures in 2020.

The natural gas sales volume increased slightly from 2,494,502 Mcf in 2020 to 2,535,188 Mcf in 2021 and the average realized per Mcf gas price increased from $1.57 in 2020 to $5.83 in 2021. The price increase was driven by a steady increase in NGL prices and a 92% increase in the underlying Henry Hub gas price, which included the impact of Winter Storm Uri in 2021. These per Mcf amounts are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. Natural gas sales volumes in 2021 were positively impacted by higher volumes associated with reservoir de-pressurization at the Northwest Shelf properties which were partially offset by purchaser inability to receive gas volumes at certain times throughout the year due to downtime or mechanical issues effecting efficiencies with their facilities.

Lease operating expenses. Our total lease operating expenses (“LOE”) increased slightly from $29,753,413 in 2020 to $30,312,399 in 2021 and increased on a Boe basis from $9.25 in 2020 to $9.75 in 2021. These per Boe amounts are calculated by dividing our total lease operating expenses by our total volume sold, in Boe. LOE increased due to the higher amount of activity in 2021 compared to the lack of activity resulting from the oil price destabilization due to the COVID-19 pandemic in 2020.

Gathering, transportation and processing costs. Our total gathering, transportation and processing costs (“GTP”) increased slightly from $4,090,238 in 2020 to $4,333,232 in 2021 and increased on a Boe basis from $1.27 in 2020 to $1.39 in 2021. GTP costs increased due to the higher gas volumes processed in the Northwest Shelf.

Ad valorem taxes. Our total ad valorem taxes decreased from $3,125,222 in 2020 to $2,276,463 in 2021 and decreased on a Boe basis from $0.97 in 2020 to $0.73 in 2021. Ad valorem taxes decreased due to the Company’s compliance department’s annual detailed review of each property’s current production, ownership, and lease operating expenses, which resulted in cost savings for the taxes assessed.

*Oil and natural gas production taxes.*Oil and natural gas production taxes as a percentage of oil and natural gas sales were 4.63% during 2020 and increased to 4.65% in 2021. The slight increase was due to higher Texas gas revenue which is taxed at 7.5%. Production taxes vary from state to state. Therefore, these taxes are likely to vary in the future depending on the mix of production we generate from various states (currently only Texas and New Mexico), and on the possibility that any state may raise its production tax rates.

*Depreciation, depletion and amortization.*Our depreciation, depletion and amortization expense decreased from $43,010,660 in 2020 to $37,167,967 in 2021. The decrease was the result of an increase in our total reserves and an average decrease of total property cost from the impairment in 2020, resulting in a reduction to our average depreciation, depletion and amortization rate from $13.37 per Boe during 2020 to $11.95 per Boe during 2021. These per Boe amounts are calculated by dividing our total depreciation, depletion and amortization expense by our total volume sold, in Boe.

Ceiling Test Write-Down. The Company did not record a ceiling test write-down during 2021. The ceiling test was calculated based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve-month period as of December 31, 2021, adjusted for market differentials, per SEC guidelines. The Company recorded a non-cash write-down of the carrying value of its proved oil and natural gas properties of $277,501,943 for the year ended December 31, 2020 as a result of ceiling test limitations, which was reflected as ceiling test impairments in the accompanying Statements of Operations. The primary reason for the write-down was a reduction in the oil price used for calculating the reserves from $52.19 in 2019 to $36.04 in 2020.

Asset retirement obligation accretion. Our asset retirement obligation ("ARO") accretion decreased from $906,616 in 2020 to $744,045 in 2021. This was a result of the reduction of ARO liabilities from the sale of certain assets in the first quarter of 2021 and plugging activities conducted throughout the year.

Operating lease expense. Our operating lease expense decreased from $1,196,372 in 2020 to $523,487 in 2021 due to the month to month leases for office equipment and compressors used in our operations on which we had previously elected to apply ASU 2016-02. The office equipment and compressors are not subject to ASU 2016-02 based on the agreement and nature of use. The costs are recorded as short-term lease costs and amounts included in Lease operating expenses. The Company terminated its Oklahoma lease as of March 31, 2021 and negotiated a reduction to its Midland office lease.

*General and administrative expenses (including share-based compensation).*General and administrative expenses decreased from $16,874,050 in 2020 to $16,068,105 in 2021. The decrease was primarily related to a $2,945,839 reduction in share-based compensation, offset by increases in salaries, accounting expenses, and non-recurring costs associated with investor relations.

Interest expense. Interest expense decreased from $17,617,614 in 2020 to $14,490,474 in 2021. The decrease was the result of having lower amounts outstanding on our credit facility throughout 2021.

Gain (loss) on derivative contracts. During 2020, the Company recorded a gain on derivative contracts of $21,366,068. During 2021, the Company incurred a loss on derivative contracts of $77,853,141. The significant change was due to the rise of crude oil prices during 2021, which was above the fixed price of the contracts.

Deposit forfeiture income.During 2021, the Company did not earn deposit forfeiture income. During 2020, the Company received $5,500,000 in non-refundable deposits from the intended buyer regarding the attempted divestiture of the Company's Delaware assets. With the cancellation of that agreement, the non-refundable deposits were recognized as income on our Statements of Operations.

Benefit from (Provision for) income taxes.The benefit from (provision for) income taxes changed from a benefit of $6,001,176 for 2020 to a provision of $90,342 for 2021. The change was primarily the result of a full valuation allowance on federal taxes in 2021 with only state tax activity recognized.

Net income (loss).The Company had a net loss of ($253,411,828) in 2020 compared to net income of $3,322,892 in 2021. The change in net income (loss) was primarily the result of the ceiling test write-down in 2020.

Liquidity and Capital Resources

Financing of Operations. We have historically funded our operations through cash available from operations and from equity offerings of our stock. Our primary source of cash in 2022 2023 was from funds generated from the sale of oil and natural gas production. These cash flows were primarily used to fund our capital expenditures. We believe the combination of the sources of capital discussed will continue to be adequate to meet our short and long-term liquidity needs.

Credit Facility. On July 1, 2014, the Company entered into a Credit Agreement with SunTrust Bank (now Truist), as lender, issuing bank and administrative agent for several banks and other financial institutions and lenders (the "Administrative Agent"), (which was amended several times) that provided for a maximum borrowing base of $1 billion with security consisting of substantially all of the assets of the Company. In April 2019, the Company amended and restated the Credit Agreement with the Administrative Agent (as amended and restated, the "Credit Facility").

On August 31, 2022, the Company modified its Credit Facility through a Second Amended and Restated Credit Agreement (the "Second Credit Agreement"), extending the maturity date of the facility to August 2026. 2026 and the syndicate was modified to add five lenders, replacing five lenders. In conjunction with the Stronghold Acquisition, with the newly acquired assets put up for collateral, the Company established a borrowing base of $600 million. The borrowing base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The borrowing base is redetermined semi-annually on each May 1 and November 1. November. The borrowing base is subject to reduction in certain circumstances such as the sale or disposition of certain oil and gas properties of the Company or its subsidiaries and cancellation of certain hedging positions.

The syndicate was modified to add five lenders, replacing five exiting lenders. Rather than Eurodollar loans, the reference rate on the Second Amended and Restated Credit Agreement is the Standard Overnight Financing Rate ("SOFR"). Beginning on the June 30, 2023 financial statements and compliance certification delivery date, SOFR. Also, the Second Amended and Restated Credit Agreement will allow for permits the Company to declare dividends for its equity owners, subject to certain limitations. These limitations, include including (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio as defined in (outstanding debt to adjusted earnings before interest, taxes, depreciation and amortization, exploration expenses, and all other non-cash charges acceptable to the Second Amended and Restated Credit Agreement, Administrative Agent) does not exceed 2.00 to 1.00, (iii) the amount of such payments does not exceed Available Free Cash Flow (as defined in the Second Credit Agreement), and (iv) the Borrowing Base Utilization Percentage (as defined in the Second Credit Agreement) is not greater than 80%, and (v) a Responsible Officer certifies that the other four conditions are satisfied.

.

The interest rate on each SOFR Loan will be the adjusted term SOFR for the applicable interest period plus a margin between 3.0% and 4.0% (depending on the then-current level of borrowing base usage). The annual interest rate on each base rate Loan is (a) the greatest of (i) the Administrative Agent's prime lending rate, (ii) the Federal Funds Rate (as defined in the Second Amended and Restated Credit Agreement) plus 0.5% per annum, (iii) the adjusted term SOFR determined on a daily basis for an interest period of one month, plus 1.00% per annum and (iv) 0.00% per annum, plus (b) a margin between 2.0% and 3.0% per annum (depending on the then-current level of borrowing base usage).

The Second Amended and Restated Credit Agreement contains certain covenants, which, among other things, require the maintenance of (i) a total Leverage Ratio (outstanding debt to adjusted earnings before interest, taxes, depreciation and amortization, exploration expenses, and all other non-cash charges acceptable to the Administrative Agent) of not more than 3.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Second Amended and Restated Credit Agreement) of 1.0 to 1.0.

The Second Credit Agreement also contains other customary affirmative and negative covenants and events of default. The Company is required to maintain on a rolling 24 months basis, hedging transactions in respect of crude oil and natural gas, on not less than 50% of the projected production from its proved, developed, producing oil and gas. If However, if the borrowing base utilization is less than 25% at the hedge testing date and the leverage ratio Leverage Ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall will be 0% from such hedge testing date to the next succeeding hedge testing date. If date and if the borrowing base utilization percentage is equal to or greater than 25%, but less than 50% and the leverage ratio Leverage Ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall will be 25% from such hedge testing date to the next succeeding hedge testing date.

The Second Amended and Restated Credit Agreement also contains other customary affirmative and negative covenants and events of default. As of December 31, 2022 December 31, 2023, $415,000,000 $425 million was outstanding on the Credit Facility. The Facility and the Company is was in compliance with all covenants contained in the Second Amended and Restated Credit Agreement as of December 31, 2022. Agreement.

Equity Offering. In October 2020, the Company closed on an underwritten public offering of (i) 9,575,800 Common Shares, (ii) 13,428,500 Pre-Funded Warrants and (iii) 23,004,300 Common Warrants at a combined purchase price of $0.70. This includes a partial exercise of the over-allotment. The Common Warrants have a term of five years and an exercise price of $0.80 per share. Gross proceeds totaled $16,089,582.

Concurrently with the underwritten public offering, the Company closed on a registered direct offering of (i) 3,500,000 Common Shares, (ii) 3,300,000 Pre-Funded Warrants and (iii) 6,800,000 Common Warrants at a combined purchase price of $0.70. The Common Warrants have a term of five years and an exercise price of $0.80 per share. Gross proceeds totaled $4,756,700.

Total gross proceeds from the 2020 underwritten public offering and the registered direct offering aggregated $20,846,282. Total net proceeds for the Common Warrants exercised in 2020 aggregated $19,379,832.

The Common Shares of 9,575,800 and 3,500,000 were issued in 2020, as shown in our Statements of Stockholders' Equity. 2020. The Pre-Funded Warrants of 3,300,000 were exercised and common stock was issued in 2020 and the 2020. The Pre-Funded Warrants of 13,428,500 were exercised and common stock was issued in 2021, as shown in our Statements of Stockholders' Equity. Of the aforementioned 6,800,000 Common Warrants, all remained outstanding as of December 31, 2021 and 2022. Of the aforementioned 23,004,300 Common Warrants, 442,600 were exercised and common stock was issued in 2021 and 2021; 10,253,907 were exercised and common stock was issued in 2022, 2022; and 19,029,593 were exercised and common stock was issued in 2023 (4,517,427 exercised at $0.80 and 14,512,166 exercised at $0.62 - refer to Note 11 — STOCKHOLDERS' EQUITY); as shown in our Statements of Stockholders' Equity.

Issuance of Common Stock and Convertible Preferred Stock for Stronghold Acquisition. As part of the consideration for the Stronghold Acquisition, on August 31, 2022 the Company issued 21,339,986 shares of common stock and 153,176 shares of newly created Series A Convertible Preferred Stock, which was converted into 42,548,892 shares of common stock on October 27, 2022.

Cash Flows. Historically, our primary sources of cash have been from operations, equity offerings and borrowings on our the Credit Facility. During 2023, 2022, 2021, and 2020 2021 we had net cash inflow from operations provided by operating activities of $198.2 million, $197.0 million, $72.7 million, and $72.2 million $72.7 million, respectively. During the three years ended December 31, 2022 December 31, 2023, we financed $28.0 million $20.9 million through proceeds from the sale of common stock. During 2023, 2022, and 2021, the Company had a net drawof$10.0 million, a net draw of $125.0 million, and 2020, we had proceeds from drawdowns a net repayment of $23.0 million on our the Credit Facility, of $636.0 million, $60.2 million, and $26.5 million, respectively. We primarily used this cash to fund our capital expenditures and development aggregating $405.2 million $596.9 million over the three years ended December 31, 2022 December 31, 2023. Additionally, during 2023, 2022 2021 and 2020, 2021, we used $511.0 million cash of $215.0 million, $83.2 million $511.0 million and $80.0 million $83.2 million, respectively, to reduce the outstanding balance on our Credit Facility. As of December 31, 2022 December 31, 2023, we had cash on hand of $0.3 million and negative working capital of $57.9 million, compared to cash on hand of $3.7 million and negative working capital of $78.0 million, compared to $78.6 million as of December 31, 2022 and cash on hand of $2.4 million and negative working capital of $46.9 million as of December 31, 2021 and cash on hand of $3.6 million and negative working capital of $16.1 million as of December 31, 2020.

Contractual Obligations. The Company maintains a Credit Facility which currently has a $600.0 $600 million borrowing base. The outstanding balance on that Credit Facility as of December 31, 2022 is $415.0 December 31, 2023 was $425.0 million, which will require repayment or refinancing at or prior to maturity in August 2026.

The Company leases office spaces in The Woodlands, Texas and Midland, Texas. The Woodlands office is was under a five-and-a-half-year lease beginning January 15, 2021. ; however, effective as of May 31, 2023, The Woodlands office sub-lease was terminated. On May 9, 2023, the Company entered into a 71-month (five years and 11-month) new lease for a larger amount of office space in The Woodlands, Texas. The Midland office lease was amended effective October 1, 2022, with the revised five-year lease ending September 30, 2027.

The Company has financing leases for vehicles with varying maturity dates through October 2025. 2026. Future lease payments through October 2025 for financing leases aggregate $1,900,595.

$2,006,453.

Subsequent Events

Stronghold acquisition***Surety Bonds*** -On January 10, 2024, two insurance companies issued surety bonds on behalf of the Company, one for $250,000, an RRC required blanket performance bond to operate 100 wells or more in the State of Texas, and one for $2,000,000, an RRC required blanket plugging extension bond, each with zero collateral requirements. The term for these two surety bonds ends on July 1, 2025 and can be renewed at that time.

First Amendment to Second Amended and Restated Credit Agreement **-** On February 28, 2023, as discussed in "Note 5 - ACQUISITIONS & DIVESTITURES," the deferred cash consideration of $15.0 million in cash was paid to Stronghold in accordance with terms set forth in the Purchase Agreement for the Stronghold Acquisition. In addition on March 1, 2023, the holdback amount of approximately $8.3 million which was held in escrow in accordance with the terms set forth in the Purchase Agreement for the Stronghold Acquisition was distributed to Stronghold.

Common stock issued pursuant to warrant exercise - On February 2, 2023 February 12, 2024, the Company, issued 2,517,427 shares of common stock pursuant Truist Bank ("Truist") as the Administrative Agent and Issuing Bank, and the lenders party thereto (the "Lenders") entered into an amendment (the "Amendment") to the exercise of Common Warrants with an exercise price of $0.80. Gross Second Amended and net proceeds were $2,013,942. On March 1, 2023 Restated Credit Agreement dated August 31, 2022, by and among the Company, issued 2,000,000 shares as Borrower, Truist as Administrative Agent and Issuing Bank, and the Lenders (together with all amendments or other modifications, the "Credit Agreement"). Among other things, the Amendment amends the definition of common stock pursuant to Free Cash Flow so amounts used by the exercise Company for acquisitions will no longer be subtracted from the calculation of Common Warrants with an exercise price of $0.80. Gross and net proceeds were $1,600,000. Free Cash Flow.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers, and others associated with the industry puts extreme significant pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do associated costs. Material changes in prices impact the our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, and the value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money, and retain personnel. We anticipate business costs will vary in accordance with commodity prices for oil and natural gas, and the associated increase or decrease in demand for services related to production and exploration.

Off-Balance Sheet Financing Arrangements

As of December 31, 2022 December 31, 2023, we had no off-balance sheet financing arrangements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operations is based upon the information reported in our financial statements. The preparation of these statements requires us to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We base our assumptions and estimates on historical experience and other sources that we believe to be reasonable at the time. Actual results may vary from our estimates due to changes in circumstances, weather, politics, global economics, mechanical problems, general business conditions and other factors. Our significant accounting policies, as well as considerations of recent accounting pronouncements, are detailed in "Note 1 -— ORGANIZATION, BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES" to our financial statements included in this Annual Report. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by our management.

Revenue Recognition. In January 2018, the Company adopted Accounting Standards Update ("ASU") 2014-09 *Revenues from Contracts with Customers (Topic 606)* ("ASU 2014-09"). The timing of recognizing revenue from the sale of produced crude oil and natural gas was not changed as a result of adopting ASU 2014-09. The Company predominantly derives its revenue from the sale of produced crude oil and natural gas. The contractual performance obligation is satisfied when the product is delivered to the customer. purchaser. Revenue is recorded in the month the product is delivered to the purchaser.

The Company receives payment from one to three months after delivery. The transaction price includes variable consideration as product pricing is based on published market prices and reduced for contract specified differentials. differentials (quality, transportation and other variables from benchmark prices). The new guidance regarding ASU 2014-09 does not require that the transaction price be fixed or stated in the contract. Estimating the variable consideration does not require significant judgment and Ring engages third party sources to validate the estimates. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration the Company expects to receive in exchange for those products. See "Note 2 - — REVENUE RECOGNITION" of our financial statements for additional information.

Full Cost Method of Accounting. We account for our oil and natural gas operations using The Company uses the full cost method of accounting. accounting for oil and natural gas properties. Under this method, all costs (internal or external) (direct and indirect) associated with property acquisition, exploration, and development of oil and natural gas reserves properties are capitalized. Costs capitalized include acquisition costs, geological and geophysical

expenditures, lease rentals on undeveloped properties and cost costs of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. All of our properties are located within the continental United States.

***Write-down of Oil and Natural Gas Properties*.** Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation each quarter. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed quarterly utilizing the average of prices in effect on the first day of the month for the preceding twelve-month period in accordance with SEC Release No. 33-8995. The ceiling limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved crude oil and natural gas reserves discounted at 10%, plus the lower of cost or market value of unproved properties, less any associated tax effects. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and results in a lower depletion, depreciation and amortization ("DD&A") rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

During 2020, the Company recorded a non-cash write-down of the carrying value of the Company's proved oil and natural gas properties as a result of a ceiling test limitation of approximately $277.5 million, which is reflected with ceiling test and other impairments in the accompanying Statements of Operations. The Company did not have any write-downs related to the full cost ceiling limitation in 2021 during the years ended December 31, 2023, 2022, or 2022. 2021.

Our estimates of reserves and future cash flow as of December 31, 2022 December 31, 2023 and 2021 2022 were prepared using an average price equal to the unweighted arithmetic average of the first day of the month price for each month within the 12-month periods ended December 31, 2022 December 31, 2023 and 2021, 2022, respectively, in accordance with SEC guidelines. As of December 31, 2023, our reserves were based on an SEC average price of $74.70 per Bbl of WTI oil posted and $2.637 per MMBtu Henry Hub natural gas. As of December 31, 2022, our reserves are were based on an SEC average price of $90.15 per Bbl of WTI oil posted and $6.358 per MMBtu Henry Hub natural gas. As of December 31, 2021, our reserves are based on an SEC average price of $63.04 per Bbl of WTI oil posted and $3.598 per MMBtu Henry Hub natural gas. Prices are adjusted by local field and lease level differentials and are held constant for life of reserves in accordance with SEC guidelines.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this Annual Report are prepared in accordance with guidelines established by the SEC and FASB. The accuracy of our reserve estimates 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 judgments of the persons preparing the estimates.

Our proved reserve information included in this Annual Report was prepared and determined by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. We continually make revisions to reserve estimates throughout the year as additional properties are acquired. We make changes to depletion rates and impairment calculations in the same period that changes to the reserve estimates are made.

All capitalized costs of oil and natural gas properties, including the estimated future costs to develop proved reserves and estimated future costs to plug and abandon wells and costs of site restoration, less the estimated salvage value of equipment associated with the oil and natural gas properties, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent petroleum engineers. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined.

Income Taxes. Deferred income taxes are provided for the difference on differences between the tax basis of assets and liabilities and their carrying amounts in the carrying amount in our financial statements. statements, and tax carryforwards. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is settled. Since our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to the actual values in the period the Company files its tax returns.

In assessing the Company's deferred tax assets, we consider whether a valuation allowance should be recorded for some or all of the deferred tax assets which may not be realized. The ultimate realization of deferred tax assets is assessed at each reporting period and is dependent upon the generation of future taxable income and the Company's ability to utilize operation loss carryforwards during the periods in which the temporary differences become deductible. We also consider the scheduled reversal of deferred tax liabilities and available tax planning strategies.

Item 7A: Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Market risk refers to the risk of loss from adverse changes in oil and natural gas prices. Realized pricing is primarily driven by the prevailing domestic price for crude oil and spot prices applicable to the region in which we produce oil and natural gas. Historically, prices received for oil and natural gas production have been volatile and unpredictable. We expect pricing volatility to continue.

The prices we receive depend on many factors outside of our control. Oil prices we received during 2022 2023 ranged from a monthly average low of $75.33 $68.72 per barrel to a monthly average high of $114.86 $89.13 per barrel. Natural gas prices we received realized during 2022 2023 ranged from a monthly average low of $2.16 $(0.94) per Mcf to a monthly average high of $9.78 $1.52 per Mcf. In some months, fees exceeded the pricing, causing a negative net realized price. Gross natural gas prices ranged from a monthly average low of $0.76 per Mcf to a monthly average high of $2.78 per Mcf. Fees ranged from a monthly average low of $(2.07) per Mcf to a monthly average high of $(0.87) per Mcf. NGL prices received during 2023 ranged from a monthly average low of $7.07 per barrel to a monthly average high of $14.71 per barrel. A significant decline in the prices of oil or natural gas could would likely have a material adverse effect on our financial condition and results of operations. In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our crude oil and natural gas, we may enter into crude oil and natural gas price hedging arrangements with respect to a portion of our expected production. The following table summarizes the Company's hedges in place on a monthly basis by commodity type. See "Note 8 - 7 — DERIVATIVE FINANCIAL INSTRUMENTS" to our financial statements for further information.

Month	Oil Hedges (WTI) Average BBL/day	Gas Hedges (Henry Hub) Average MMBtu/day
January 2023	5,180	3,862
February 2023	5,145	11,652
March 2023	5,113	11,580
April 2023	4,832	11,259
May 2023	4,802	11,188
June 2023	4,774	11,119
July 2023	4,497	10,802
August 2023	4,471	10,735
September 2023	4,447	10,669
October 2023	4,423	10,356
November 2023	4,400	10,294
December 2023	4,379	10,233
January 2024	4,150	6,500
February 2024	4,132	6,500
March 2024	4,113	6,500
April 2024	4,096	6,250
May 2024	4,081	6,250
June 2024	4,066	6,250
July to September 2024	3,750	6,000
October to December 2024	4,000	6,000

Month	Oil Hedges (WTI) Average BBL/day	Gas Hedges (Henry Hub) Average MMBtu/day
January 2024	6,475	—
February 2024	6,457	8,999
March 2024	6,438	8,311
April 2024	5,921	8,383
May 2024	5,906	7,999

June 2024	5,891	8,124
July 2024	5,575	7,704
August 2024	5,575	7,590
September 2024	5,575	7,722
October 2024	5,400	7,336
November 2024	5,400	7,467
December 2024	5,400	7,133
January 2025	5,275	7,023
February 2025	5,275	7,633
March 2025	5,275	6,831
April 2025	5,100	6,961
May 2025	5,100	6,662
June 2025	5,100	6,790
July to September 2025	4,450	6,450
October to December 2025	4,400	6,500

Customer Credit Risk

Our principal exposure to credit risk is through receivables from the sale of our oil and natural gas production (approximately $40.1 $37.9 million as of December 31, 2022 December 31, 2023). We are subject to credit risk due to the concentration of our oil and natural gas receivables with our most significant customers. customers, or purchasers. We do not require our customers purchasers to post collateral, and the inability of our significant customers purchasers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For The following table sets forth certain information regarding the year ended December 31, 2022, sales to top three customers, Phillips, NGL Crude, and Enterprise represented 68%, 13% and 5%, respectively, purchasers of our oil, natural gas, and natural gas liquids revenues. As of December 31, 2022, Phillips represented 69% of our accounts receivable, NGL Crude represented 7% of our accounts receivable and Enterprise represented 10% of our accounts receivable. NGLs for the year ended December 31, 2023. We believe that the loss of any of these customers purchasers would not materially impact our business because we could readily find other purchasers for our oil and natural gas.

	For the Year Ended	As of
	December 31, 2023	December 31, 2023
	Percentage of Oil, Natural Gas, and Natural Gas Liquids Revenues	Percentage of accounts receivables from the sale of our oil and natural gas production
Purchaser:		
Phillips 66 Company ("Phillips")	66%	65%
Enterprise Crude Oil LLC ("Enterprise")	12%	11%
NGL Crude Partners ("NGL Crude")	10%	8%

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our Credit Facility, which bears variable interest based upon a prime rate and is therefore susceptible to interest rate fluctuations.

Changes in interest rates affect the interest earned on the Company's cash and cash equivalents and the interest rate paid on borrowings under the Credit Facility.

As of December 31, 2022 December 31, 2023, we had $415.0 $425.0 million outstanding on our Credit Facility with a weighted average annual interest rate for the year then ended of 5.8% 8.8%. A 1% change in the interest rate on our Credit Facility would result in an estimated $4.2 million $4.3 million change in our annual interest expense. See "Note 10 - 9 — REVOLVING LINE OF CREDIT" in the Footnotes notes to the financial statements for more information on the Company's interest rates on of our Credit Facility.

Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes.

Currency Exchange Rate Risk

Foreign sales accounted for none of the Company's sales; the Company accepts payment for its commodity sales only in U.S. dollars. Ring is therefore not exposed to foreign currency exchange rate risk on these sales.

Please also see Item 1A "Risk Factors" above for a discussion of other risks and uncertainties we face in our business.

Item 8: Financial Statements and Supplementary Data

The financial statements and supplementary data required by this item are included beginning at page F-1 of this Annual Report.

Item 9: Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A: Controls and Procedures

Evaluation of disclosure controls and procedures.

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2022 December 31, 2023, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of December 31, 2022 December 31, 2023, our disclosure controls and procedures are effective.

Changes in internal control over financial reporting.

We regularly review our system of internal control over financial reporting and make changes to our processes and systems to improve controls and increase efficiency, while ensuring that we maintain an effective internal control environment. Changes may include such activities as implementing new, more efficient systems, consolidating activities, and migrating processes.

There were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2022 December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting and Report of Independent Accounting Firm

Our management is responsible for establishing and maintaining adequate internal controls over financial reporting. Our internal control system is designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Furthermore, the effectiveness of a system of internal control over financial reporting in future periods can change as conditions change.

In making our assessment of internal control over financial reporting, our management used the criteria issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework (2013)*. Based on our assessment, we believe that, as of December 31, 2022 December 31, 2023, our internal control over financial reporting is effective based on those criteria.

The independent registered public accounting firm, Grant Thornton LLP, has audited the financial statements and internal control over financial reporting included in this Annual Report on Form 10-K, and has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2022 December 31, 2023. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2022 December 31, 2023, is set forth below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Ring Energy, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Ring Energy, Inc. (a Nevada corporation) (the "Company") as of December 31, 2022December 31, 2023, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022December 31, 2023, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the financial statements of the Company as of and for the year ended December 31, 2022December 31, 2023, and our report dated March 9, 2023March 7, 2024 expressed an unqualified opinion on those financial statements.

Basis for opinion

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

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

Definition and limitations of internal control over financial reporting

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

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

/s/ GRANT THORNTON LLP

Houston, Texas
March 9, 20237, 2024

Item 9B: Other Information

None.

On March 6, 2024, the Board, upon the recommendation of the compensation committee of the Board (the "Compensation Committee"), approved the Ring Energy, Inc. Change in Control and Severance Benefit Plan (the "CIC Plan") which provides for severance benefits to our named executive officers (and certain other officers and key employees), including: Paul D. McKinney, Chairman of the Board and Chief Executive Officer (the "Tier 1 NEO"), and Marinos Baghdati, Executive Vice President of Operations, Stephen D. Brooks, Executive Vice President of Land, Legal, Human Resources and Marketing, Alexander Dyes, Executive Vice President of Engineering and Corporate Strategy, and Travis T. Thomas Executive Vice President and Chief Financial Officer (collectively, the "Tier 2 NEOs" and with the Tier 1 NEO, collectively, the "NEOs"). The CIC Plan supersedes and replaces all other severance arrangements between the Company and the NEOs, which previously had been governed by separate employment agreements.

Pursuant to the CIC Plan, following a Change in Control (as defined in the CIC Plan) and during the "protection period," which period extends from the date six months prior to a Change in Control until the date 24 months following the occurrence of a Change in Control, if the Tier 1 NEO's employment is terminated by the Company without Cause (as defined in the CIC Plan) or by him for a CIC Good Reason (as defined in the CIC Plan), he is entitled to (1) 300% of his annual base salary; (2) 300% of his most recent target annual bonus (the "AIP Amount"); (3) 100% of his pro-rated AIP Amount (based on the number of days employed during the year of termination); (4) acceleration and vesting of his outstanding equity awards; and (5) reimbursement of 24 months of health benefits.

In addition, following the Tier 1 NEO's death or disability, he would be entitled to (1) acceleration and vesting of his outstanding equity awards; and (2) reimbursement of 12 months of health benefits.

Pursuant to the CIC Plan, if the Tier 1 NEO's employment with the Company is terminated by the Company without Cause or by him for a Good Reason (as defined in the CIC Plan) and not during the applicable protection period, he is entitled to receive (1) 200% of his annual base salary, (2) 200% of his AIP Amount; (3) 100% of his pro-rated AIP Amount (based on the number of days employed during the year of termination); (4) acceleration and vesting of his outstanding equity awards; and (5) reimbursement of 24 months of health benefits.

Pursuant to the CIC Plan, following a Change in Control and during the "protection period," which period extends from the date six months prior to a Change in Control until the date 24 months following the occurrence of a Change in Control, if the Tier 2 NEO's employment is terminated by the Company without Cause or by him for a CIC Good Reason, he is entitled to (1) 200% of his annual base salary; (2) 200% of his AIP Amount; (3) 100% of his pro-rated AIP Amount (based on the number of days employed during the year of termination); (4) acceleration and vesting of his outstanding equity awards; and (5) reimbursement of 18 months of health benefits.

In addition, following the Tier 2 NEO's death or disability, he would be entitled to (1) acceleration and vesting of his outstanding equity awards; and (2) reimbursement of 12 months of health benefits.

Pursuant to the CIC Plan, if the Tier 2 NEO's employment with the Company is terminated by the Company without Cause or by him for a Good Reason and not during the applicable protection period, he is entitled to receive (1) 100% of his annual base salary; (2) 100% of his AIP Amount; (3) 100% of his pro-rated AIP Amount (based on the number of days employed during the year of termination); (4) acceleration and vesting of his outstanding equity awards; and (5) reimbursement of 18 months of health benefits.

Entitlement to the above benefits is conditioned on the timely execution of a general release in the form and substance approved by the Compensation Committee, and each executive's compliance with non-competition, non-solicitation and confidentiality covenants set forth in the CIC Plan.

In order to be eligible to receive benefits under the CIC Plan, the executives must execute and return to the Company a participation agreement (a "Participation Agreement") the form of which is attached as Exhibit B to the CIC Plan. Upon the execution of a Participation Agreement, the executive's prior employment agreement terminates, and the continued employment of such executive will be on an at-will basis. On March 6, 2024, Messrs. McKinney, Baghdati, Brooks, Dyes and Thomas became participants in the CIC Plan upon their delivery to the Company of executed Participation Agreements, pursuant to which the NEOs agreed to terminate the existing employment agreements between them and the Company, effective immediately, and the terms of the CIC Plan and respective Participation Agreements supersede any rights or entitlements to severance benefits under any employment agreement so terminated or other severance arrangements. The CIC Plan does not affect the NEOs' eligibility to their base salary, subject to increase at the discretion of the Board, or the Compensation Committee, and to participate in any and all other standard benefit plans, programs and policies of the Company.

The description of the CIC Plan contained in this Item 9B does not purport to be complete and is qualified in its entirety by reference to the CIC Plan included as Exhibit 10.25 to this Annual Report.

Item 9C: Disclosure Regarding Foreign Jurisdictions that Prevent Inspections

None.

PART III

Item 10: Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated by reference herein from the Company's 2023 2024 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022 December 31, 2023. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

Item 11: Executive Compensation

The information required by this item is incorporated by reference herein from the Company's 2023 2024 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022 December 31, 2023. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

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

The information required by this item is incorporated by reference herein from the Company's 2023 2024 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022 December 31, 2023. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

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

The information required by this item is incorporated by reference herein from the Company's 2023 2024 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022 December 31, 2023. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

Item 14: Principal Accountant Fees and Services

The information required by this item is incorporated by reference herein from the Company's 2023 2024 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2022 December 31, 2023. If the Proxy Statement is not filed with the SEC by such time, such information will be included in an amendment to this Annual Report by such time.

PART IV

Item 15: Exhibits and Financial Statement Schedules

Exhibit Number	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Here-with
2.1	Purchase and Sale Agreement, dated February 25, 2019 by and among Ring Energy, Inc. and Wishbone Energy Partners, LLC, Wishbone Texas operating Company LLC and WB WaterWorks, LLC	8-K	001-36057	2.1	2/28/19	
2.2	Purchase and Sale Agreement dated July 1, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, a Delaware limited liability company (“Stronghold OpCo”) and Stronghold Energy II Royalties, LP, a Delaware limited partnership, including the following Exhibits thereto: Exhibit I – Form of Registration Rights Agreement, Exhibit K – Form of Nomination Agreement, Exhibit L – Form of Certificate of Designation and Exhibit M – Form of Lock-Up Agreement	8-K	001-36057	2.1	7/8/22	
2.2(a)	First Amendment to Purchase and Sale Agreement by and among Stronghold Energy II Operating, LLC, Stronghold Energy II Royalties, LP, and Ring Energy, Inc., dated August 4, 2022	8-K	001-36057	2.1	8/9/22	
3.1	Articles of Incorporation (as amended)	10-K	000-53920	3.1	4/1/13	
3.1(a)	Certificate of Amendment to the Articles of Incorporation, as amended, of Ring Energy, Inc.	8-K	001-36057	3.1	12/17/21	
3.2	Bylaws of Ring Energy, Inc. as amended April 13, 2021	8-K	001-36057	3.1	4/15/21	
3.3	Certificate of Designation of the Series A Convertible Preferred Stock dated August 30, 2022	8-K	001-36057	3.1	9/6/22	
3.4	Certificate of Withdrawal of Certificate of Designation filed with the Secretary of State of Nevada effective October 31, 2022	8-K	001-36057	3.1	10/31/22	
4.1	Registration Rights Agreement, dated April 9, 2019 by and between Ring Energy, Inc. and Wishbone Energy Partners, LLC	10-Q	001-36057	4.1	4/12/19	
4.2	Description of Ring Energy, Inc. equity securities registered under Section 12(b) of the Securities Exchange Act of 1934, as amended	10-K	001-36057	10.16	3/16/21	
4.3	Securities Purchase Agreement, dated October 27, 2020	8-K	001-36057	4.1	10/29/20	
10.1*	Executive Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Stephen D. Brooks	8-K	001-36957	10.1	12/4/20	
10.2*	Executive Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Paul D. McKinney	8-K	001-36957	10.1	10/6/20	
10.3*	Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Alexander Dyes	8-K	001-36057	10.1	12/22/20	
10.4*	Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Marinos C. Baghdati	8-K	001-36057	10.2	12/22/20	

Exhibit Number	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Here-with	Furn-ished Here-with
2.1	Purchase and Sale Agreement, dated February 25, 2019 by and among Ring Energy, Inc. and Wishbone Energy Partners, LLC, Wishbone Texas operating Company LLC and WB WaterWorks, LLC	8-K	001-36057	2.1	2/28/19		

2.2	Purchase and Sale Agreement dated July 1, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, a Delaware limited liability company ("Stronghold OpCo") and Stronghold Energy II Royalties, LP, a Delaware limited partnership, including the following Exhibits thereto: Exhibit I – Form of Registration Rights Agreement, Exhibit K – Form of Nomination Agreement, Exhibit L – Form of Certificate of Designation and Exhibit M – Form of Lock-Up Agreement	8-K	001-36057	2.1	7/8/22	
2.2(a)	First Amendment to Purchase and Sale Agreement by and among Stronghold Energy II Operating, LLC, Stronghold Energy II Royalties, LP, and Ring Energy, Inc., dated August 4, 2022	8-K	001-36057	2.1	8/9/22	
2.3	Asset Purchase Agreement dated July 10, 2023 between Ring Energy, Inc. and Founders Oil & Gas IV, LLC.	8-K	001-36057	2.1	7/14/23	
3.1	Articles of Incorporation (as amended)	10-K	000-53920	3.1	4/1/13	
3.1(a)	Certificate of Amendment to the Articles of Incorporation, as amended, of Ring Energy, Inc.	8-K	001-36057	3.1	12/17/21	
3.1(b)	Certificate of Amendment to the Articles of Incorporation, as amended, of Ring Energy, Inc.	8-K	001-36057	3.1	5/26/23	
3.2	Bylaws of Ring Energy, Inc. as amended April 13, 2021	8-K	001-36057	3.1	4/15/21	
3.3	Certificate of Designation of the Series A Convertible Preferred Stock dated August 30, 2022	8-K	001-36057	3.1	9/6/22	
3.4	Certificate of Withdrawal of Certificate of Designation filed with the Secretary of State of Nevada effective October 31, 2022	8-K	001-36057	3.1	10/31/22	
4.1	Registration Rights Agreement, dated April 9, 2019 by and between Ring Energy, Inc. and Wishbone Energy Partners, LLC	10-Q	001-36057	4.1	4/12/19	
4.2	Description of Ring Energy, Inc. equity securities registered under Section 12(b) of the Securities Exchange Act of 1934, as amended					X
4.3	Securities Purchase Agreement, dated October 27, 2020	8-K	001-36057	4.1	10/29/20	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Here-with
		Form	File No.	Exhibit	Filing Date	
10.5*	Ring Energy Inc. Long Term Incentive Plan, as Amended	8-K	000-53920	99.3	1/24/13	
10.6*	Form of Option Grant for Long-Term Incentive Plan	10-Q	000-53920	10.2	8/14/12	
10.7	Credit Agreement dated July 1, 2014 with SunTrust Bank	8-K	001-36057	10.1	7/3/14	
10.8	First Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	6/29/15	
10.9	Second Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	7/29/15	
10.10	Third Amendment to Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	5/20/16	
10.11	Fourth Amendment to Credit Agreement with SunTrust Bank	10-K	001-36057	10.16	3/16/21	
10.12	Fifth Amendment to Credit Agreement with SunTrust	8-K	001-36057	10.1	6/19/18	
10.13	Amended and Restated Credit Agreement with SunTrust Bank	10-Q	001-36057	10.2	5/8/19	
10.14	First Amendment to Amended and Restated Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	12/9/19	
10.15	Second Amendment to Amended and Restated Credit Agreement, dated June 17, 2020, by and among Ring Energy, Inc., the lenders party thereto, and Truist Bank, as administrative agent for the lenders and as issuing bank	8-K	001-36057	10.1	6/19/20	
10.16	Third Amendment to Amended and Restated Credit Agreement with Truist Bank	8-K	001-36057	10.1	12/29/20	

10.17	Fourth Amendment to Amended and Restated Credit Agreement with Truist Bank dated June 10, 2021	8-K	001-36057	10.1	6/16/21
10.18	Fifth Amendment to Amended and Restated Credit Agreement with Truist Bank dated June 25, 2021	8-K	001-36057	10.1	6/25/21
10.19*	Executive Employment and Severance Agreement, dated as of October 26, 2020, by and between the Company and Travis T. Thomas	8-K	001-36057	10.1	3/26/21
10.20	Registration Rights Agreement dated August 31, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, and Stronghold Energy II Royalties, LP.	8-K	001-36057	10.1	9/6/22
10.21	Lock-up Agreement dated August 31, 2022, by and between Ring Energy, Inc. and Stronghold Energy II Operating, LLC.	8-K	001-36057	10.2	9/6/22
10.22	Director Nomination Agreement dated August 31, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, and Stronghold Energy II Royalties, LP.	8-K	001-36057	10.3	9/6/22
10.23	Second Amended and Restated Credit Agreement dated August 31, 2022, by and among Ring Energy, Inc., Truist Bank, and the Lenders from time to time party thereto	8-K	001-36057	10.4	9/6/22

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	File No.	Exhibit	Filing Date	Filed Here-with	Furn-ished Here-with
10.1*	Executive Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Stephen D. Brooks	8-K	001-36957	10.1	12/4/20		
10.2*	Executive Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Paul D. McKinney	8-K	001-36957	10.1	10/6/20		
10.3*	Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Alexander Dyes	8-K	001-36057	10.1	12/22/20		
10.4*	Employment and Severance Agreement, dated as of September 30, 2020, by and between the Company and Marinos C. Baghdati	8-K	001-36057	10.2	12/22/20		
10.5*	Ring Energy Inc. Long Term Incentive Plan, as Amended	8-K	000-53920	99.3	1/24/13		
10.6*	Form of Option Grant for Long-Term Incentive Plan	10-Q	000-53920	10.2	8/14/12		
10.7	Amended and Restated Credit Agreement with SunTrust Bank	10-Q	001-36057	10.2	5/8/19		
10.8	First Amendment to Amended and Restated Credit Agreement with SunTrust Bank	8-K	001-36057	10.1	12/9/19		
10.9	Second Amendment to Amended and Restated Credit Agreement, dated June 17, 2020, by and among Ring Energy, Inc., the lenders party thereto, and Truist Bank, as administrative agent for the lenders and as issuing bank	8-K	001-36057	10.1	6/19/20		
10.10	Third Amendment to Amended and Restated Credit Agreement with Truist Bank	8-K	001-36057	10.1	12/29/20		
10.11	Fourth Amendment to Amended and Restated Credit Agreement with Truist Bank dated June 10, 2021	8-K	001-36057	10.1	6/16/21		
10.12	Fifth Amendment to Amended and Restated Credit Agreement with Truist Bank dated June 25, 2021	8-K	001-36057	10.1	6/25/21		
10.13*	Executive Employment and Severance Agreement, dated as of October 26, 2020, by and between the Company and Travis T. Thomas	8-K	001-36057	10.1	3/26/21		
10.14	Registration Rights Agreement dated August 31, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, and Stronghold Energy II Royalties, LP.	8-K	001-36057	10.1	9/6/22		

10.15	Lock-up Agreement dated August 31, 2022, by and between Ring Energy, Inc. and Stronghold Energy II Operating, LLC.	8-K	001-36057	10.2	9/6/22	
10.16	Director Nomination Agreement dated August 31, 2022, by and among Ring Energy, Inc., Stronghold Energy II Operating, LLC, and Stronghold Energy II Royalties, LP.	8-K	001-36057	10.3	9/6/22	

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	File No.	Exhibit	Filing Date	Filed Here-with
10.24*	Ring Energy, Inc. 2021 Omnibus Incentive Plan	DEF 14A	001-36057		4/22/21	
10.25*	Form of Performance Stock Unit Agreement	8-K	001-36057	10.1	11/30/21	
10.26*	Form Restricted Stock Unit Agreement (employees)	8-K	001-36057	10.1	2/23/23	
10.27*	Form of Restricted Stock Unit Agreement (non-employee directors)	8-K	001-36057	10.2	2/23/23	
14.1	Code of Ethics	8-K	000-53920	14.1	1/24/13	
23.1	Consent of Cawley, Gillespie & Associates, Inc.					X
23.2	Consent of Grant Thornton LLP					X
23.3	Consent of Eide Bailly LLP					X
24.1	Power of Attorney (included as part of the signature pages of this report)					X
31.1	Rule 13a-14(a) Certification by Chief Executive Officer					X
31.2	Rule 13a-14(a) Certification by Chief Financial Officer					X
32.1	Section 1350 Certification of Chief Executive Officer					X
32.2	Section 1350 Certification Chief Financial Officer					X
99.1	Reserve Report of Cawley, Gillespie & Associates, Inc.					X
101.INS	Inline XBRL Instance Document					X
101.SCH	Inline XBRL Taxonomy Extension Schema Document					X
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document					X
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document					X
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document					X
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).					

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	File No.	Exhibit	Filing Date	Filed Here-with	Furn-ished Here-with
10.17	Second Amended and Restated Credit Agreement dated August 31, 2022, by and among Ring Energy, Inc., Truist Bank, and the Lenders from time to time party thereto	8-K	001-36057	10.4	9/6/22		
10.18*	Ring Energy, Inc. 2021 Omnibus Incentive Plan	DEF 14A	001-36057		4/22/21		
10.19*	Amendment No. 1 to the Ring Energy, Inc. 2021 Omnibus Incentive Plan	8-K	001-36057	10.1	5/26/23		
10.20*	Form of Performance Stock Unit Agreement	8-K	001-36057	10.1	11/30/21		
10.21*	Form Restricted Stock Unit Agreement (employees)	8-K	001-36057	10.1	2/23/23		

10.22*	Form of Restricted Stock Unit Agreement (non-employee directors)	8-K	001-36057	10.2	2/23/23		
10.23	Form of Warrant Amendment and Exercise Agreement.	8-K	001-36057	10.1	4/12/23		
10.24	First Amendment to Second Amended and Restated Credit Agreement dated as of February 12, 2024, by and among Ring Energy, Inc., Truist Bank, as administrative agent, and the Lenders party thereto.	8-K	001-36057	10.1	2/16/24		
10.25	Change in Control and Severance Benefit Plan					X	
14.1	Code of Ethics	8-K	000-53920	14.1	1/24/13		
23.1	Consent of Cawley, Gillespie & Associates, Inc.					X	
23.2	Consent of Grant Thornton LLP					X	
24.1	Power of Attorney (included as part of the signature pages of this report)					X	
31.1	Rule 13a-14(a) Certification by Chief Executive Officer					X	
31.2	Rule 13a-14(a) Certification by Chief Financial Officer					X	
32.1	Section 1350 Certification of Chief Executive Officer						X
32.2	Section 1350 Certification Chief Financial Officer						X
97.1	Ring Energy, Inc. Clawback Policy					X	
99.1	Reserve Report of Cawley, Gillespie & Associates, Inc.					X	
101.INS	Inline XBRL Instance Document					X	
101.SCH	Inline XBRL Taxonomy Extension Schema Document					X	
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase Document					X	
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase Document					X	
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase Document					X	

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**File No.**	**Exhibit**	**Filing Date**	**Filed Here-with**	**Furn-ished Here-with**
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase Document					X	
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).						

* Management contract

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.

Ring Energy, Inc.

By: */s/ Paul D. McKinney*

Mr. Paul D. McKinney

Chief Executive Officer

Date: March 9, 2023 March 7, 2024

KNOW ALL PERSONS BY THESE PRESENTS, that each individual whose signature appears below constitutes and appoints Paul D. McKinney, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K filed with the Securities and Exchange Commission, hereby ratifying and confirming his signature as he may be signed by his or her said attorney to any and all amendments to said Annual Report on Form 10-K.

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 on the dates indicated.

/s/ Paul D. McKinney	*/s/ Thomas L. Mitchell*
Mr. Paul D. McKinney	Mr. Thomas L. Mitchell
Chief Executive Officer and Director	Director
(Principal Executive Officer)	Date: March 7, 2024
Date: March 9, 2023 March 7, 2024	Date: March 9, 2023
/s/ Travis T. Thomas	*/s/ Anthony B. Petrelli*
Mr. Travis T. Thomas	Mr. Anthony B. Petrelli
Chief Financial Officer	Director
(Principal Financial Officer)	Date: March 7, 2024
Date: March 9, 2023 March 7, 2024	Date: March 9, 2023
/s/ Regina Roesener	*/s/ Clayton E. Woodrum*
Mrs. Regina Roesener	Mr. Clayton E. Woodrum
Director	Director
Date: March 7, 2024	Date: March 7, 2024
Date: March 9, 2023	Date: March 9, 2023
/s/ Richard E. Harris	*/s/ John A. Crum*
Mr. Richard E. Harris	Mr. John A. Crum
Director	Director
Date: March 7, 2024	Date: March 7, 2024
Date: March 9, 2023	Date: March 9, 2023
/s/ Roy I. Ben-Dor	*/s/ David S. Habachy*
Mr. Roy I. Ben-Dor	Mr. David S. Habachy
Director	Director
Date: March 7, 2024	
Date: March 9, 2023	Date: March 9, 2023 March 7, 2024

RING ENERGY, INC.

INDEX TO FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Ring Energy, Inc.

Opinion on the financial statements

We have audited the accompanying balance sheets of Ring Energy, Inc. (a Nevada corporation) (the "Company") as of December 31, 2022December 31, 2023 and 2021,2022, the related statements of operations, stockholders' equity, and cash flows for each of the twothree years in the period ended December 31, 2022December 31, 2023, 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, 2022December 31, 2023 and 2021,2022, and the results of its operations and its cash flows for each of the twothree years in the period ended December 31, 2022December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2022December 31, 2023, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated March 9, 2023March 7, 2024 expressed an unqualified opinion.

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 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. 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 matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates 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 matter below, providing separate opinions on the critical audit matter or on the accounts or disclosures to which it relates.

The development of estimated proved crude oil and natural gas reserves used in the calculation of depletion, depreciation and amortization expense under the full cost method of accounting and the valuation of crude oil and natural gas properties in the 2022 Stronghold Acquisition (herein referred to as "the crude oil and natural gas reserves")

As described further in Note 1 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting, which requires management to make estimates of proved crude oil and natural gas reserve volumes and future net revenues to record depletion, depreciation and amortization expense. Additionally, as described in Note 5 to the financial statements, the Company acquired significant oil and natural gas properties through an asset acquisition. Crude oil and natural gas reserves are a significant input to the determination of the acquisition date value of crude oil and natural gas properties acquired by the Company in the asset acquisition. To estimate the volume of proved crude oil and natural gas reserves and future net revenue, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved crude oil and natural gas reserves is impacted by management's judgments and estimates regarding the financial performance of wells associated with proved crude oil and natural gas reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion,

depreciation and amortization expense. We identified the estimation of proved reserves of oil and gas properties as it relates to the recognition of depletion, depreciation and amortization expense and recording the values of properties acquired in the 2022 Stronghold Acquisition as a critical audit matter.

The principal consideration for our determination that the estimation of proved crude oil and natural gas reserves as it relates to the recognition of depletion, depreciation and amortization expense and the recording of oil and natural gas property values in the 2022 Stronghold acquisition is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future net revenues of the Company's proved reserves could have a significant impact on the measurement of depletion, depreciation and amortization expense and the acquisition date values of oil and natural gas properties. expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved crude oil and natural gas reserves included the following, among others.

- We tested the design and operating effectiveness of controls relating to management's estimation of proved crude oil and natural gas reserves for the purpose of estimating depletion, depreciation and amortization expense and acquisition date value of crude oil and natural gas properties. expense.

- We evaluated the independence, objectivity, and professional qualifications of the Company's reserve engineers, made inquiries of those specialists regarding the process followed and judgments made to estimate the Company's proved crude oil and natural gas reserve volumes, and read the reserve report prepared by the Company's specialists.

- To the extent key inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, including, but not limited to: historical pricing differentials, operating costs, estimated capital costs, and ownership interests, we tested management's process for determining the assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's assumptions by performing the following:

    - We compared the estimated pricing differentials used in the reserve report to prices realized by the Company related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials.

    - As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we compared the pricing differentials used in the reserve report to the differentials provided by the seller, and performed analytical procedures by comparing the differentials in the reserve report to actual differentials realized subsequent to the acquisition close date.

    - We tested models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs.

    - As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we recalculated the operating costs in the reserve report based on the model provided by the seller, and performed analytical procedures by comparing the operating costs in the reserve report to operating costs realized subsequent to the acquisition close date.

    - We evaluated the method used to determine the estimated future development costs used in the reserve report and compared management's estimates to amounts expended for recently drilled and completed wells.

    - As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we compared the estimated future development costs in the reserve report to the model provided by the seller, and we performed analytical procedures by comparing the future

      development costs in the reserve report to actual development costs incurred subsequent to the acquisition close date.

    - We tested the working and net revenue interests used in the reserve report by inspecting land, legal and division order records.

    - We evaluated evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties. properties, and

    - We applied analytical procedures to production forecasts in the reserve report by comparing to historical actual results.

    - As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition we applied analytical procedures to production forecasts by comparing the remaining forecast in 2022 in the reserve report to actual results subsequent to the acquisition close date.

- As it relates to the recording of the acquisition date values of crude oil and natural gas properties in the asset acquisition, we utilized internal valuation specialists to assist with evaluating certain assumptions, such as risk-adjustment factors, as compared to industry surveys and publicly available market data.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2021.

Houston, Texas
March 9, 2023

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Stockholders of Ring Energy, Inc.
The Woodlands, Texas

Opinions on the Financial Statements

We have audited the accompanying statements of operations, stockholders' equity, and cash flows of Ring Energy, Inc. (Ring Energy) for the year ended December 31, 2020 and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the results of its operations and its cash flows for the year ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the entity's management. Our responsibility is to express an opinion on these financial statements based on our audit. 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 Ring Energy 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 audit 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.

Our audit included performing procedures to assess the risk 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 audit 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 audit provides a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the audit of the financial statements that were communicated or required to be communicated to the audit committee that (1) relate to accounts or disclosures that are material to the financial statements and (2) involve our especially challenging, subjective, or complex judgement. 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.

Depletion expense and ceiling test calculation of oil and natural gas properties impacted by the estimation of proved oil and natural gas reserves

As described further in Note 1 to the financial statements, the Company uses the full cost method of accounting for oil and natural gas properties. This accounting method requires management to make estimates of proved oil and natural gas reserves and related future cash flows to compute and record depreciation, depletion and amortization expense, as well as to assess potential impairment of oil and natural gas properties (the full cost ceiling test). To estimate the volume of proved oil and natural gas reserves quantities, management makes significant estimates and assumptions including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved oil and natural gas reserves is also impacted by management's judgements and estimates regarding the financial performance of wells associated with those proved oil and natural gas reserves to determine if wells are expected to be economical under the appropriate pricing assumptions that are required in the estimation of depreciation, depletion and amortization expense and potential ceiling test impairment assessments. We identified the estimation of proved oil and natural gas reserves as it relates to the recognition of depreciation, depletion and amortization expense and the assessment of potential impairment as a critical audit matter.

The principal consideration for our determination that the estimation of proved oil and natural gas reserves is a critical audit matter is that there is significant judgement by management and use of specialist in developing the estimates of proved oil and natural gas reserves and a relatively minor change in certain inputs and assumptions that are necessary to estimate the volume and future cash flows of the Company's proved oil and natural gas reserves could have a significant impact on the measurement of depreciation, depletion and amortization expense and/or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgement.

Our audit procedures related to the estimation of proved oil and natural gas reserves included the following, among others.

- We tested the design and operating effectiveness of internal controls relating to management's estimation of proved oil and natural gas reserves for the purpose of estimating depreciation, depletion and amortization expense and assessing for ceiling test impairment.
- We evaluated the independence, objectivity, and professional qualifications of the Company's independent petroleum engineer specialist and read the report prepared by the Company's independent petroleum engineer specialist.
- We evaluated the sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions that are derived from the Company's accounting records, such as historical pricing differentials, operating costs, estimated capital costs, and ownership interests. We tested management's process for determining the assumptions, including the underlying support, on a sample basis where applicable. Specifically, our audit procedures involved testing management's assumptions as follows:
    - Tested the working and net revenue interest used in the reserve report
    - Tested the model used to determine the future capital expenditures by comparing estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells, where applicable;
    - Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year;
    - Tested the model used to estimate the operating costs at year end and compared to historical operating costs;
    - Evaluated the Company's evidence supporting the proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's ability to fund and intent to develop the proved undeveloped properties.

Valuation Allowance of Deferred Tax Assets

As described in Note 1 to the financial statements, the Company records a valuation allowance to reduce total net deferred tax assets when a judgement is made that is considered more likely than not that a tax benefit will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences will become deductible. We identified the realizability of deferred tax assets as a critical audit matter.

The principal considerations for our determination that the realizability of deferred tax assets is a critical audit matter are that (a) the forecast of future taxable income is subject to a high level of estimation and (b) the determination of any limitations on the utilization of net operating loss carryforwards involve complex calculations and judgement. There is inherent uncertainty and subjectivity related to management's judgements and assumptions regarding the Company's future taxable income, which are complex in nature and require significant auditor judgment.

Our audit procedures related to the valuation of deferred tax assets included the following, among others.

- We tested the effectiveness of controls over management's estimate of the realization of the deferred tax assets and management's tax planning strategies and the determination of whether it is more likely than not that the deferred tax assets will be realized prior to expiration.
- We tested the reasonableness of management's corporate model used to estimate future taxable income by comparing the estimates to the following:
    - Historical taxable income.
    - Evidence obtained in other areas of the audit.
    - Management's history of carrying out its stated plans and its ability to carry out its plans.

We have served as Ring Energy's auditor since 2013. Hansen, Barnett and Maxwell, P.C., who joined Eide Bailly LLP in 2013, had served as the Company's auditor since 2012.

0001628280-23-007323rei-20221231_g2.jpg

Denver, Colorado
March 16, 20217, 2024

RING ENERGY, INC.
BALANCE SHEETS

As of December 31,	As of December 31,	2022	2021	As of December 31,	2023	2022
ASSETS	**ASSETS**					
Current Assets	**Current Assets**					
Current Assets						
Current Assets						
Cash and cash equivalents						
Cash and cash equivalents						
Cash and cash equivalents	Cash and cash equivalents	$ 3,712,526	$ 2,408,316			
Accounts receivable	Accounts receivable	42,448,719	24,026,807			
Joint interest billing receivable		983,802	2,433,811			
Joint interest billing receivables, net						
Derivative assets	Derivative assets	4,669,162	—			
Inventory	Inventory	9,250,717	—			
Prepaid expenses and other assets	Prepaid expenses and other assets	2,101,538	938,029			
Total Current Assets	**Total Current Assets**	63,166,464	29,806,963			
Properties and Equipment	**Properties and Equipment**					
Oil and natural gas properties, full cost method						
Oil and natural gas properties, full cost method						
Oil and natural gas properties, full cost method	Oil and natural gas properties, full cost method	1,463,838,595	883,844,745			
Financing lease asset subject to depreciation	Financing lease asset subject to depreciation	3,019,476	1,422,487			
Fixed assets subject to depreciation	Fixed assets subject to depreciation	3,147,125	2,089,722			
Total Properties and Equipment	**Total Properties and Equipment**	1,470,005,196	887,356,954			
Accumulated depreciation, depletion and amortization	Accumulated depreciation, depletion and amortization	(289,935,259)	(235,997,307)			
Net Properties and Equipment	**Net Properties and Equipment**	1,180,069,937	651,359,647			
Operating lease asset	**Operating lease asset**	1,735,013	1,277,253			
Derivative assets	**Derivative assets**	6,129,410	—			
Deferred financing costs	**Deferred financing costs**	17,898,973	1,713,466			
Total Assets	**Total Assets**	$ 1,268,999,797	$ 684,157,329			
LIABILITIES AND STOCKHOLDERS' EQUITY	**LIABILITIES AND STOCKHOLDERS' EQUITY**					
LIABILITIES AND STOCKHOLDERS' EQUITY						
LIABILITIES AND STOCKHOLDERS' EQUITY						

Current Liabilities				
Current Liabilities				
Current Liabilities	**Current Liabilities**			
Accounts payable	Accounts payable	$ 111,398,268	$ 46,233,452	
Accounts payable				
Accounts payable				
Financing lease liability				
Financing lease liability				
Financing lease liability	Financing lease liability	709,653	316,514	
Operating lease liability	Operating lease liability	398,362	290,766	
Derivative liabilities	Derivative liabilities	13,345,619	29,241,588	
Notes payable	Notes payable	499,880	586,410	
Deferred cash payment	Deferred cash payment	14,807,276	—	
Asset retirement obligations				
Total Current Liabilities	**Total Current Liabilities**	141,159,058	76,668,730	
Non-current Liabilities	**Non-current Liabilities**			
Non-current Liabilities				
Non-current Liabilities				
Deferred income taxes				
Deferred income taxes				
Deferred income taxes	Deferred income taxes	8,499,016	90,292	
Revolving line of credit	Revolving line of credit	415,000,000	290,000,000	
Financing lease liability, less current portion	Financing lease liability, less current portion	1,052,479	343,727	
Operating lease liability, less current portion	Operating lease liability, less current portion	1,473,897	1,138,319	
Derivative liabilities	Derivative liabilities	10,485,650	—	
Asset retirement obligations	Asset retirement obligations	30,226,306	15,292,054	
Total Liabilities	**Total Liabilities**	607,896,406	383,533,122	
Commitments and contingencies				
Commitments and Contingencies - See Note				Commitments and Contingencies - See Note
Stockholders' Equity	**Stockholders' Equity**			
Preferred stock - $0.001 par value; 50,000,000 shares authorized; no shares issued or outstanding	Preferred stock - $0.001 par value; 50,000,000 shares authorized; no shares issued or outstanding	—	—	
Common stock - $0.001 par value; 225,000,000 shares authorized; 175,530,212 shares and 100,192,562 shares issued and outstanding, respectively		175,530	100,193	

Preferred stock - $0.001 par value; 50,000,000 shares authorized; no shares issued or outstanding

Preferred stock - $0.001 par value; 50,000,000 shares authorized; no shares issued or outstanding

Common stock - $0.001 par value; 450,000,000 shares authorized; 196,837,001 shares and 175,530,212 shares issued and outstanding, respectively

Additional paid-in capital	Additional paid-in capital	775,241,114	553,472,292
Accumulated deficit	Accumulated deficit	(114,313,253)	(252,948,278)
Total Stockholders' Equity	**Total Stockholders' Equity**	661,103,391	300,624,207
Total Liabilities and Stockholders' Equity	**Total Liabilities and Stockholders' Equity**	$ 1,268,999,797	$ 684,157,329

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

RING ENERGY, INC.
STATEMENTS OF OPERATIONS

For the years ended December 31,	*For the years ended December 31,*	2022	2021	2020
Oil, Natural Gas, and Natural Gas Liquids Revenues	**Oil, Natural Gas, and Natural Gas Liquids Revenues**	$347,249,537	$196,305,966	$ 113,025,138
Costs and Operating Expenses	**Costs and Operating Expenses**			
Lease operating expenses	Lease operating expenses	47,695,351	30,312,399	29,753,413

For the years ended December 31,	2023	2022	2021

Oil, Natural Gas, and Natural Gas Liquids Revenues

Oil, Natural Gas, and Natural Gas Liquids Revenues

Costs and Operating Expenses

Costs and Operating Expenses

Lease operating expenses

Lease operating expenses

Gathering, transportation and processing costs	Gathering, transportation and processing costs	1,830,024	4,333,232	4,090,238
Ad valorem taxes	Ad valorem taxes	4,670,617	2,276,463	3,125,222
Oil and natural gas production taxes	Oil and natural gas production taxes	17,125,982	9,123,420	5,228,090
Depreciation, depletion and amortization	Depreciation, depletion and amortization	55,740,767	37,167,967	43,010,660
Ceiling test impairment		—	—	277,501,943
Asset retirement obligation accretion				
Asset retirement obligation accretion				
Asset retirement obligation accretion	Asset retirement obligation accretion	983,432	744,045	906,616
Operating lease expense	Operating lease expense	363,908	523,487	1,196,372
General and administrative expense	General and administrative expense	27,095,323	16,068,105	16,874,050
Total Costs and Operating Expenses	**Total Costs and Operating Expenses**	155,505,404	100,549,118	381,686,604
Total Costs and Operating Expenses				
Total Costs and Operating Expenses				
Income (Loss) from Operations		191,744,133	95,756,848	(268,661,466)
Income from Operations				
Income from Operations				
Income from Operations				
Other Income (Expense)	**Other Income (Expense)**			
Other Income (Expense)				
Other Income (Expense)				
Interest income				
Interest income				
Interest income	Interest income	4	1	8
Interest (expense)	Interest (expense)	(23,167,729)	(14,490,474)	(17,617,614)
Gain (loss) on derivative contracts	Gain (loss) on derivative contracts	(21,532,659)	(77,853,141)	21,366,068
Deposit forfeiture income		—	—	5,500,000

Loss on disposal of assets			
Other income			
Net Other Income (Expense) Net Other Income (Expense)	(44,700,384)	(92,343,614)	9,248,462
Income (Loss) Before Provision for Income Taxes	147,043,749	3,413,234	(259,413,004)
Income Before Provision for Income Taxes			
Income Before Provision for Income Taxes			
Income Before Provision for Income Taxes			
Benefit from (Provision for) Income Taxes	(8,408,724)	(90,342)	6,001,176
Net Income (Loss)	$138,635,025	$ 3,322,892	$(253,411,828)
Provision for Income Taxes			
Provision for Income Taxes			
Provision for Income Taxes			
Net Income			
Basic Earnings (Loss) per share	$ 1.14	$ 0.03	$ (3.48)
Diluted Earnings (Loss) per share	$ 0.98	$ 0.03	$ (3.48)
Basic Earnings per Share			
Basic Earnings per Share			
Basic Earnings per Share			
Diluted Earnings per Share			

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

RING ENERGY, INC.
STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount			
Balance, December 31, 2019	67,993,797	$ 67,994	$526,301,281	$ (2,859,342)	$523,509,933
Return of common stock issued as consideration in asset acquisition	(16,702)	(17)	(103,368)	—	(103,385)
Common stock and warrants issued for cash, net	13,075,800	13,076	19,366,756	—	19,379,832
Exercise of pre-funded warrants issued in offering	3,300,000	3,300	—	—	3,300
Common stock issued for services	35,000	35	23,765	—	23,800
Restricted stock vested	1,180,392	1,180	(1,180)	—	—
Share-based compensation	—	—	5,364,162	—	5,364,162

		Common Stock Shares	Common Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Net (loss)		—	—	—	(253,411,828)	(253,411,828)
Balance, December 31, 2020						
Balance, December 31, 2020						
Balance, December 31, 2020	**Balance, December 31, 2020**	85,568,287	$ 85,568	$550,951,415	$(256,271,170)	$294,765,813
Common stock and warrants issued for cash, net	Common stock and warrants issued for cash, net	—	$ —	$ (65,000)	$ —	$ (65,000)
Exercise of pre-funded warrants issued in offering	Exercise of pre-funded warrants issued in offering	13,428,500	13,429	—	—	13,429
Exercise of common warrants issued in offering	Exercise of common warrants issued in offering	442,600	443	353,637	—	354,080
Options exercised	Options exercised	100,000	100	199,900	—	200,000
Restricted stock vested	Restricted stock vested	785,357	785	(785)	—	—
Shares to cover tax withholdings		(132,182)	(132)	132	—	—
Payments to cover tax withholdings		—	—	(385,330)	—	(385,330)
Shares to cover tax withholdings for restricted stock vested						
Payments to cover tax withholdings for restricted stock vested, net						
Share-based compensation	Share-based compensation	—	—	2,418,323	—	2,418,323
Net (loss)		—	—	—	3,322,892	3,322,892
Net income						
Balance, December 31, 2021	**Balance, December 31, 2021**	100,192,562	$100,193	$553,472,292	$(252,948,278)	$300,624,207
Exercise of common warrants issued in offering						
Exercise of common warrants issued in offering						
Exercise of common warrants issued in offering	Exercise of common warrants issued in offering	10,253,907	10,254	8,192,872	—	8,203,126
Options exercised	Options exercised	100,000	100	(100)	—	—

Shares elected to be withheld for options exercised	Shares elected to be withheld for options exercised	(47,506)	(48)	48	—	—
Restricted stock vested	Restricted stock vested	1,310,894	1,311	(1,311)	—	—
Shares to cover tax withholdings for restricted stock vested	Shares to cover tax withholdings for restricted stock vested	(168,523)	(169)	169	—	—
Payments to cover tax withholdings for restricted stock vested		—	—	(521,199)	—	(521,199)
Common stock issuance for Stronghold		21,339,986	21,340	69,120,215	—	69,141,555
Conversion of mezzanine preferred shares for Stronghold		42,548,892	42,549	137,815,897	—	137,858,446
Payments to cover tax withholdings for restricted stock vested, net						
Common stock issuance for Stronghold Acquisition						
Conversion of mezzanine preferred shares for Stronghold Acquisition						
Share-based compensation	Share-based compensation	—	—	7,162,231	—	7,162,231
Net income	Net income	—	—	—	138,635,025	138,635,025
Balance, December 31, 2022	**Balance, December 31, 2022**	175,530,212	$175,530	$775,241,114	$(114,313,253)	$661,103,391
Exercise of common warrants issued in offering						
Induced exercise of common warrants issued in offering						
Restricted stock vested						
Restricted stock vested						
Restricted stock vested						
Shares to cover tax withholdings for restricted stock vested						
Payments to cover tax withholdings for restricted stock vested, net						
Performance stock vested						
Performance stock vested						
Performance stock vested						

Shares to cover tax withholdings for performance stock vested									
Share-based compensation									
Net income									
Balance, December 31, 2023									

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

RING ENERGY, INC.
STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	*For the Years Ended December 31,*	2022	2021	2020	*For the Years Ended December 31,*	2023	2022	2021
Cash Flows From Operating Activities	**Cash Flows From Operating Activities**							
Net income (loss)		$138,635,025	$ 3,322,892	$(253,411,828)				
Adjustments to reconcile net income (loss) to net cash provided by operating activities:								
Net income								
Net income								
Net income								
Adjustments to reconcile net income to net cash provided by operating activities:								
Depreciation, depletion and amortization	Depreciation, depletion and amortization	55,740,767	37,167,967	43,010,660				
Ceiling test impairment		—	—	277,501,943				
Depreciation, depletion and amortization								
Depreciation, depletion and amortization								
Asset retirement obligation accretion								
Asset retirement obligation accretion								
Asset retirement obligation accretion	Asset retirement obligation accretion	983,432	744,045	906,616				
Amortization of deferred financing costs	Amortization of deferred financing costs	2,706,021	665,882	1,190,109				
Share-based compensation	Share-based compensation	7,162,231	2,418,323	5,364,162				

Bad debt expense	Bad debt expense	242,247	—	—
Shares issued for services		—	—	23,800
Deferred income tax expense (benefit)				
Deferred income tax expense (benefit)				
Deferred income tax expense (benefit)	Deferred income tax expense (benefit)	8,720,992	265,479	(3,975,170)
Excess tax expense (benefit) related to share-based compensation	Excess tax expense (benefit) related to share-based compensation	(312,268)	(175,187)	(2,026,006)
(Gain) loss on derivative contracts	(Gain) loss on derivative contracts	21,532,659	77,853,141	(21,366,068)
Cash received (paid) for derivative settlements, net		(62,525,954)	(52,768,154)	22,522,591
Changes in assets and liabilities:				
Cash paid for derivative settlements, net				
Changes in operating assets and liabilities:				
Accounts receivable				
Accounts receivable				
Accounts receivable	Accounts receivable	(17,214,150)	(9,483,639)	7,896,517
Inventory	Inventory	(5,597,845)	—	—
Prepaid expenses and other assets	Prepaid expenses and other assets	(1,163,509)	(541,920)	3,586,146
Accounts payable	Accounts payable	50,808,461	15,449,215	(8,380,594)
Settlement of asset retirement obligation	Settlement of asset retirement obligation	(2,741,380)	(2,186,832)	(683,623)
Net Cash Provided by Operating Activities	**Net Cash Provided by Operating Activities**	196,976,729	72,731,212	72,159,255
Cash Flows From Investing Activities	**Cash Flows From Investing Activities**			
Payments for the Stronghold Acquisition	Payments for the Stronghold Acquisition	(177,823,787)	—	—
Payments for the Stronghold Acquisition				

Payments for the Stronghold Acquisition				
Payments for the Founders Acquisition				
Payments to purchase oil and natural gas properties	Payments to purchase oil and natural gas properties	(1,563,703)	(1,368,437)	(1,317,313)
Payments to develop oil and natural gas properties	Payments to develop oil and natural gas properties	(129,332,155)	(51,302,131)	(42,457,745)
Payments to acquire or improve fixed assets subject to depreciation	Payments to acquire or improve fixed assets subject to depreciation	(319,945)	(568,832)	(55,339)
Sale of fixed assets subject to depreciation	Sale of fixed assets subject to depreciation	134,600	—	—
Proceeds from divestiture of oil and natural gas properties	Proceeds from divestiture of oil and natural gas properties	23,700	2,000,000	—
Net Cash (Used in) Investing Activities		(308,881,290)	(51,239,400)	(43,830,397)
Proceeds from sale of Delaware properties				
Proceeds from sale of New Mexico properties				
Net Cash Used in Investing Activities				
Cash Flows From Financing Activities	**Cash Flows From Financing Activities**			
Proceeds from revolving line of credit				
Proceeds from revolving line of credit				
Proceeds from revolving line of credit	Proceeds from revolving line of credit	636,000,000	60,150,000	26,500,000
Payments on revolving line of credit	Payments on revolving line of credit	(511,000,000)	(83,150,000)	(80,000,000)
Proceeds from issuance of common stock and warrants	Proceeds from issuance of common stock and warrants	8,203,126	367,509	19,383,131
Proceeds from option exercise	Proceeds from option exercise	—	200,000	—
Payments for taxes withheld on vested restricted shares		(521,199)	(385,330)	—

Payments for taxes withheld on vested restricted shares, net				
Proceeds from notes payable	Proceeds from notes payable	1,323,354	1,297,718	—
Payments on notes payable	Payments on notes payable	(1,409,884)	(711,308)	—
Payment of deferred financing costs	Payment of deferred financing costs	(18,891,528)	(104,818)	(355,049)
Reduction of financing lease liabilities	Reduction of financing lease liabilities	(495,098)	(325,901)	(282,928)
Net Cash Provided by (Used in) Financing Activities	**Net Cash Provided by (Used in) Financing Activities**	113,208,771	(22,662,130)	(34,754,846)
Net Increase (Decrease) in Cash	**Net Increase (Decrease) in Cash**	1,304,210	(1,170,318)	(6,425,988)
Cash at Beginning of Period	**Cash at Beginning of Period**	2,408,316	3,578,634	10,004,622
Cash at End of Period	**Cash at End of Period**	$ 3,712,526	$ 2,408,316	$ 3,578,634

RING ENERGY, INC.
STATEMENTS OF CASH FLOWS (CONTINUED)

For the Years Ended December 31,	*For the Years Ended December 31,*	2022	2021	2020	*For the Years Ended December 31,*	2023	2022	2021
Supplemental Cash Flow Information								
Supplemental Cash Flow Information								
Supplemental Cash Flow Information	**Supplemental Cash Flow Information**							
Cash paid for interest	Cash paid for interest	$ 19,818,623	$14,110,421	$16,911,344				
Cash paid for interest								
Cash paid for interest								
Cash paid for income taxes								
Noncash Investing and Financing Activities	**Noncash Investing and Financing Activities**							
Noncash Investing and Financing Activities								
Noncash Investing and Financing Activities								
Asset retirement obligation incurred during development								

Asset retirement obligation incurred during development

Asset retirement obligation incurred during development	Asset retirement obligation incurred during development	$ 353,008	$ 171,390	$ 99,436
Asset retirement obligation acquired	Asset retirement obligation acquired	14,538,550	662,705	—
Asset retirement obligation revision of estimate	Asset retirement obligation revision of estimate	—	435,419	34,441
Asset retirement obligation sold	Asset retirement obligation sold	—	(2,934,126)	—
Operating lease assets obtained in exchange for new operating lease liability	Operating lease assets obtained in exchange for new operating lease liability	754,894	839,536	823,727
Operating lease asset revision	Operating lease asset revision	—	(621,636)	—
Financing lease assets obtained in exchange for new financing lease liability	Financing lease assets obtained in exchange for new financing lease liability	952,101	—	—
Stock issued in property acquisition returned in final settlement		—	—	103,385
Capitalized expenditures attributable to drilling projects financed through current liabilities		9,179,003	309,365	1,415,073

Change in capitalized expenditures attributable to drilling projects financed through current liabilities

Change in capitalized expenditures attributable to drilling projects financed through current liabilities

Change in capitalized expenditures attributable to drilling projects financed through current liabilities

Supplemental Schedule for Founders Acquisition

Supplemental Schedule for Founders Acquisition

Supplemental Schedule for Founders Acquisition

Investing Activities - Cash Paid
Investing Activities - Cash Paid
Investing Activities - Cash Paid
Escrow deposit released at closing
Escrow deposit released at closing
Escrow deposit released at closing
Closing amount paid to Founders
Interest from escrow deposit
Direct transaction costs
Post-close adjustments
Payment of deferred cash payment
Payments for the Founders Acquisition
Investing Activities - Noncash
Assumption of suspense liability
Assumption of suspense liability
Assumption of suspense liability
Assumption of asset retirement obligation
Assumption of ad valorem tax liability
Deferred cash payment at fair value
Supplemental Schedule for Stronghold Acquisition | **Supplemental Schedule for Stronghold Acquisition**
Supplemental Schedule for Stronghold Acquisition

Supplemental Schedule for Stronghold Acquisition

Investing Activities - Cash Paid	***Investing Activities - Cash Paid***			
Investing Activities - Cash Paid				
Investing Activities - Cash Paid				
Cash paid by bank to Stronghold on closing				
Cash paid by bank to Stronghold on closing				
Cash paid by bank to Stronghold on closing	Cash paid by bank to Stronghold on closing	$121,392,455	$ —	$ —
Deposit in escrow	Deposit in escrow	46,500,000	—	—
Direct transaction costs	Direct transaction costs	9,162,143	—	—
Cash paid for realized August oil derivative losses	Cash paid for realized August oil derivative losses	1,777,925	—	—
Cash paid for inventory and fixed assets acquired	Cash paid for inventory and fixed assets acquired	4,527,103	—	—
Cash received for post-close adjustments, net	Cash received for post-close adjustments, net	(5,535,839)	—	—
Payment of deferred cash payment				
Payment of post-close settlement				
Payments for the Stronghold Acquisition	Payments for the Stronghold Acquisition	$177,823,787	$ —	$ —
Investing Activities - Noncash	***Investing Activities - Noncash***			
Assumption of suspense liability				
Assumption of suspense liability				
Assumption of suspense liability	Assumption of suspense liability	1,651,596	—	—

Assumption of derivative liabilities	Assumption of derivative liabilities	24,784,406	—	—
Assumption of asset retirement obligation	Assumption of asset retirement obligation	14,538,550	—	—
Deferred cash payment at fair value	Deferred cash payment at fair value	14,807,276	—	—
Financing Activities - Noncash	***Financing Activities - Noncash***			
Common stock issued for acquisition	Common stock issued for acquisition	69,141,555	—	—
Common stock issued for acquisition				
Common stock issued for acquisition				
Convertible preferred stock issued for acquisition	Convertible preferred stock issued for acquisition	$137,858,446	$ —	$ —

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

RING ENERGY, INC.
NOTES TO FINANCIAL STATEMENTS

Index to the Notes to the Financial Statements

NOTE 1 – — ORGANIZATION, BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations – Ring Energy, Inc., a Nevada corporation ("Ring," "Ring Energy," the "Company," "we," "us," "our," or similar terms), is a growth oriented independent oil and natural gas exploration and production company based in The Woodlands, Texas and is engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas. Our primary drilling operations target the oil and liquids rich producing formations in the Northwest Shelf and the Central Basin Platform, and the Delaware Basin, all of which are part of in the Permian Basin in Texas and New Mexico. Texas.

Reclassifications Liquidity and Capital Considerations – Certain prior period amounts relating The Company strives to components maintain an adequate liquidity level to address volatility and risk. Sources of liquidity include the Company's net cash provided by operating expense activities, cash on hand, available borrowing capacity under its revolving credit facility, and proceeds from sales of non-strategic assets.

While changes in oil and natural gas prices affect the Company's liquidity, the Company has put in place hedges in seeking to protect a substantial portion of its cash flows from price declines; however, if oil or natural gas prices rapidly deteriorate due to unanticipated economic conditions, this could still have been reclassified a material adverse effect on the Company’s cash flows.

The Company expects ongoing oil price volatility over an indeterminate term. Extended depressed oil prices have historically had and could have a material adverse impact on the Company’s oil revenue, which is mitigated to conform some extent by the Company’s hedge contracts. The Company is always mindful of oil price volatility and its impact on our liquidity.

The Company believes that it has the ability to current year presentation within “Costs continue to fund its operations and Operating Expenses” in the Statements of Operations. Additionally, certain prior amounts associated with realized and unrealized gains (losses) have been reclassified within the Statements of Operations and Statements of Cash Flows to conform with current year presentation. service its debt by using cash flows from operations.

Use of Estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (“GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses during the reporting period. The Company's financial statements are based on a number of significant estimates, including estimates of oil and natural gas reserve quantities, which are the basis for the calculation of depletion and impairment of oil and gas properties. Reserve estimates, by their nature, are inherently imprecise. Actual results could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analysis could have a significant impact on the Company's future results of operations.

Fair Value Measurements - Fair value is 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 Financial Accounting Standards Board (“FASB”) has established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure

fair value. This hierarchy consists of three broad levels. Level 1 inputs are the highest priority and consist of unadjusted quoted prices in active markets for identical assets and liabilities. Level 2 are inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly. Level 3 are unobservable inputs for an asset or liability.

Fair Values of Financial Instruments – The carrying amounts reported for the our revolving line of credit approximates approximate their fair value because the underlying instruments are at interest rates which approximate current market rates. The carrying amounts of receivables accounts receivable and accounts payable and other current assets and liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities.

Fair Value of Non-financial Assets and Liabilities – The Company also applies fair value accounting guidance to initially, or as events dictate, measure non-financial assets and liabilities such as those obtained through business acquisitions, property and equipment and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two as considered appropriate based on the circumstances. Under the discounted cash flow method, estimated future cash flows are based on management’s expectations for the future and include estimates of future oil and natural gas production or other applicable sales estimates, operational costs and a risk-adjusted discount rate. The Company may use the present value of estimated future cash inflows and/or outflows or third-party offers or prices of comparable assets with consideration of current market conditions to value its non-financial assets and liabilities when circumstances dictate determining fair value is necessary. Given the significance of the unobservable nature of a number of the inputs, these are considered Level 3 on the fair value hierarchy.

Concentration of Credit Risk and Accounts Receivable Receivables – Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and accounts receivable. receivables.

Cash and cash equivalents - The Company has cash in excess of federally insured limits of $3,462,526 $46,384 and $1,936,805 $3,462,526 as of December 31, 2022 December 31, 2023 and 2021, 2022, respectively. The Company places its cash with a high credit quality financial institution. The Company has not experienced any losses in such accounts and believes it is not exposed to significant credit risk in this area.

Accounts receivable - Substantially all of the Company’s accounts receivable is from purchasers of oil and natural gas. Oil and natural gas sales are generally unsecured. Accounts receivable from purchasers outstanding longer than the contractual payment terms are considered past due. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectable. The Company also has a joint interest billing receivable. Joint interest billing receivables are collateralized by the pro rata revenue attributable Refer to the joint interest holders and further by the interest itself. Accounts receivable from joint interest owners or purchasers outstanding longer than the contractual payment terms are considered past due. For "*Major Purchasers*" section below for detail on purchaser activity for the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020, the Company provided for bad debt expense of $242,247, $0, and $0 respectively, associated with its joint interest billing receivable. As of December 31, 2022 and 2021, the Company's allowance for credit losses was $242,247 and $0, respectively, associated with its joint interest billing receivable. 2021.

Production imbalances - The Company accounts for natural gas production imbalances using the sales method, which recognizes revenue on all natural gas sold even though the natural gas volumes sold may be more or less than the Company's ownership entitles it to sell. Liabilities are recorded for imbalances greater than the Company’s proportionate share of remaining estimated natural gas reserves. The Company recorded no imbalances as of December 31, 2022 December 31, 2023 or 2022.

Joint interest billing receivables, net - The Company also has a joint interest billing receivable. Joint interest billing receivables are collateralized by the pro rata revenue attributable to the joint interest holders and further by the interest itself. Receivables from joint interest owners outstanding longer than the contractual payment terms are considered past due. The following table indicates the Company's provisions for bad debt expense associated with its joint interest billing receivables during the years ended December 31, 2023, 2022, and 2021.

	For the Years Ended December 31,		
	2023	2022	2021
Bad debt expense	$134,007	$242,247	$0

The following table reflects the Company's joint interest billing receivables and allowance for credit losses as of December 31, 2023 and 2022.

	2023		2022	
Joint interest billing receivables	$	2,480,843	$	1,226,049
Allowance for credit losses		(58,569)		(242,247)
Joint interest billing receivables, net	$	2,422,274	$	983,802

The reduction of $183,678 in the allowance for credit losses during the year ended December 31, 2023 was primarily due to a clearing of $105,620 in allowances that were associated with the Delaware Basin asset sale.

Cash and Cash Equivalents – The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. At December 31, 2023 and 2022, the Company had no such investments.

Inventory - During 2022, The full balance of the Company purchased Company's inventory consists of materials and supplies inventories for its operations, with no work in bulk to lock in prices with certain vendors. Additionally, as a part of the Stronghold Acquisition (discussed further in "Note 5 - ACQUISITIONS & DIVESTITURES"), the Company acquired an process or finished goods inventory yard with significant amounts of inventory. balances. Inventory is added to the books upon the purchase of supplies (inclusive of freight and sales tax costs) to use on well sites, and inventory is reduced by material transfers for inventory usage based on the initial invoiced value. We report The Company reports the balance of our its inventory at the lower of cost or market net realizable value. Inventory balances are excluded from the Company's calculation of depletion.

Oil and Natural Gas Properties – The Company uses the full cost method of accounting for oil and natural gas properties. Under this method, all costs (direct and indirect) associated with acquisition, exploration, and development of oil and natural gas properties are capitalized. Costs capitalized include acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. Capitalized costs are categorized either as being subject to amortization or not subject to amortization. All of the Company's capitalized costs, excluding inventory, are subject to amortization.

The Company records a liability in the period in which an asset retirement obligation ("ARO") is incurred, in an amount equal to the discounted estimated fair value of the obligation that is capitalized. Thereafter this liability is accreted up to the final retirement cost. An ARO is a future expenditure related to the disposal or other retirement of certain assets. The Company's ARO relates to future plugging and abandonment expenses of its oil and natural gas properties and related facilities disposal. Dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs.

All capitalized costs of oil and natural gas properties, including the estimated future costs to develop proved reserves and estimated future costs to plug and abandon wells and costs of site restoration, less the estimated salvage value of equipment associated with the oil and natural gas properties, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent petroleum engineers. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is offset to the capitalized costs to be amortized. The following table shows total depletion and the depletion per barrel-of-oil-equivalent rate, for the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020. 2021.

		For the Years Ended December 31,					
		2022	2021	2020			
	For the Years Ended December 31,				For the Years Ended December 31,		
	2023				2023	2022	2021
Depletion	Depletion	$55,029,956	$36,735,070	$42,634,294			
Depletion rate, per barrel-of-oil-equivalent (Boe)	Depletion rate, per barrel-of-oil-equivalent (Boe)	$ 12.19	$ 11.82	$ 13.25			

In addition, capitalized costs less accumulated depreciation, depletion and amortization and related deferred income taxes shall are not allowed to exceed an amount (the full cost ceiling) equal to the sum of:

1) the present value of estimated future net revenues discounted at ten percent computed in compliance with SEC guidelines;

2) plus the cost of properties not being amortized;

3) plus the lower of cost or estimated fair value of unproven properties included in the costs being amortized;

4) less income tax effects related to differences between the book and tax basis of the properties.

For the year ended December 31, 2020, the Company recognized an impairment No impairments on oil and natural gas properties as a result of the ceiling test in the amount of $277,501,943. No impairment was were recorded for the years ended December 31, 2022 December 31, 2023, 2022 or 2021.

Land, Buildings, Equipment, and Software, Leasehold Improvements, Automobiles, Buildings and Structures – Land, buildings, equipment, and software, leasehold improvements, automobiles, buildings and structures are carried at historical cost, adjusted for impairment loss and accumulated depreciation. depreciation (except for land). Historical costs include all direct costs associated with the acquisition of land, buildings, equipment, and software, leasehold improvements, automobiles, buildings and structures and placing them in service. Upon sale or abandonment, the cost of the fixed asset(s) and related accumulated depreciation are removed from the accounts and any gain or loss is recognized.

Depreciation of buildings, equipment, , software, and leasehold improvements, automobiles, buildings and structures is calculated using the straight-line method based upon the following estimated useful lives:

Leasehold improvements	3-5 years
Office equipment and software	3-7 years
Equipment	5-10 years
Automobiles	4 years
Buildings and structures	7 years

Depreciation The following table provides information on the Company's depreciation expense was $205,600, $432,897, and $376,366 for the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020, respectively. 2021.

	For the Years Ended December 31,		
	2023	**2022**	**2021**
Depreciation expense	$364,024	$205,600	$124,961

During the year endedDecember 31, 2023, the Company sold some of its automobiles, and recognized a loss on disposal of $87,128.

Accounts Payable

The following table summarizes the Company's components of its current accounts payable balance presented in its Balance Sheets at December 31, 2023 and 2022:

	2023	**2022**
Trade accounts payable	$ 37,626,348	$ 40,480,684
Revenues payable	44,348,938	43,807,208
Accrued expenses	22,088,838	27,110,376
Accounts payable	**$ 104,064,124**	**$ 111,398,268**

Trade accounts payable– The following table summarizes the Company's current trade accounts payable at December 31, 2023 and 2022:

	2023	**2022**
Accounts payable related to vendors	$ 36,944,263	$ 36,586,007
Other	682,085	3,894,677
Trade accounts payable	**$ 37,626,348**	**$ 40,480,684**

Revenues payable– The following table summarizes the Company's current revenues and royalties payable at December 31, 2023 and 2022:

	2023	2022
Revenue held in suspense	$ 31,592,825	$ 30,180,940
Revenues and royalties payable	12,756,113	13,626,268
Revenues payable	**$ 44,348,938**	**$ 43,807,208**

Accrued expenses – The following table summarizes the Company's current accrued expenses at December 31, 2023 and 2022:

	2023	2022
Accrued capital expenditures	$ 7,518,603	$ 9,624,985
Accrued lease operating expenses	6,798,548	6,450,356
Accrued interest	3,684,378	3,222,864
Accrued general and administrative expense	4,047,095	4,076,699
Other	40,214	3,735,472
Accrued expenses	**$ 22,088,838**	**$ 27,110,376**

Notes Payable – During 2022, At the end of May 2023, the Company renewed its directors and officers, control of well, general liability, pollution, umbrella, property, workers' compensation, auto, and cybersecurity D&O (directors and officers) insurance policies, and funded the premiums with three a promissory notes note with a total face value after down payments of $1,323,354. $1,565,071. In November 2023, the Company renewed its cybersecurity insurance policy, and funded the premium with a promissory note with a total face value after down payments of $72,442. The annual percentage rate (APR) for both notes is 7.08%. As of December 31, 2022 December 31, 2023, the notes payable balance included within current liabilities on the balance sheet is $499,880. During 2021, the Company obtained external insurance for the same policies and funded the premiums by signing three promissory notes. $533,734. The annual percentage rate (APR) for these weighted average notes is 4.08%. For payable balance during the years ended December 31, 2022 December 31, 2023 and 2021, 2022 were $687,456 and $593,766, respectively. The average interest on the weighted average notes payable balance during the years ended December 31, 2023 and 2022 were 7.23% and 4.31%, respectively. The following table shows interest paid related to notes payable was $25,579 for the years ended December 31, 2023, 2022, and $17,824, respectively, 2021. This interest is included within "Interest (expense)" in the Statements of Operations.

	For the Years Ended December 31,		
	2023	2022	2021
Interest paid for notes payable	$ 49,734	$ 25,579	$ 17,824

Revenue Recognition – In January 2018, the Company adopted Accounting Standards Update ("ASU") 2014-09 *Revenues from Contracts with Customers (Topic 606)* ("ASU 2014-09"). The timing of recognizing revenue from the sale of produced crude oil and natural gas was not changed as a result of adopting ASU 2014-09. The Company predominantly derives its revenue from the sale of produced crude oil and natural gas. The contractual performance obligation is satisfied when the product is delivered to the customer. purchaser. Revenue is recorded in the month the product is delivered to the purchaser. The Company receives payment from one to three months after delivery. The transaction price includes variable consideration as product pricing is based on published market prices and reduced for contract specified differentials. differentials (quality, transportation and other variables from benchmark prices). The new guidance regarding ASU 2014-09 does not require that the transaction price be fixed or stated in the contract. Estimating the variable consideration does not require significant judgment and Ring engages third party sources to validate the estimates. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration the Company expects to receive in exchange for those products. See "Note 2 - — REVENUE RECOGNITION" for additional information.

Income Taxes – Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes. Deferred income taxes are provided on differences between the tax basis of assets and liabilities and their reported carrying amounts in the financial statements, and tax carryforwards. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the provision for income taxes.

Since December 31, 2020, the Company determined that a full valuation allowance was necessary due to the Company's assessment that it was more likely than not that it would be unable to obtain the benefits of its deferred tax assets due to the Company's history of taxable losses. The Company determined that certain existing deferred tax assets would not be offset by existing deferred tax liabilities as a result of the 80% limitation on the utilization of net operating losses incurred after 2017. Since 2021, commodity prices increased and the Company continues to project positive pre-tax book income. As of June 30, 2023, the Company was no longer in a cumulative loss position. As a result, future forecasted pre-tax book income was considered as positive evidence in assessing the valuation allowance. Based on the change in judgment on the realizability of the related federal deferred tax assets in future years, the Company released $24.2 million of valuation allowance as a benefit during the year ended December 31, 2023. The Company recorded the following federal and state income tax benefits (provisions) for the years ended December 31, 2023, 2022, and 2021.

	For the Years Ended December 31,		
	2023	2022	2021
Deferred federal income tax benefit (provision)	$ 901,522	$ (6,437,680)	$ —
Current state income tax provision	(72,213)	—	—
Deferred state income tax provision	(954,551)	(1,971,044)	(90,342)

Provision for Income Taxes	$ (125,242)	$ (8,408,724)	$ (90,342)

The Company's overall effective tax rates (calculated as Provision for Income Taxes divided by Income Before Provision for Income Taxes) for the years ended December 31, 2023, 2022, and 2021 were as follows.

	For the Years Ended December 31,		
	2023	2022	2021
Effective tax rate	0.1 %	5.7 %	2.6 %

These rates were primarily impacted by the release of valuation allowance on the Company's federal net deferred tax asset. A tax benefit of $24.2 million was recorded in the year ended December 31, 2023.

Accounting for Uncertainty in Income Taxes – In accordance with GAAP, the Company has analyzed its filing positions in all jurisdictions where it is required to file income tax returns for the open tax years in such jurisdictions. years. The Company has identified its federal income tax return and its franchise tax return in Texas in which it operates as a "major" tax jurisdictions. jurisdiction. The Company's federal income tax returns for the years ended December 31, 2018 December 31, 2019 and after remain subject to examination. The Company's federal income tax returns for the years ended December 31, 2007 and after remain subject to examination to the extent of the net operating loss (NOL) carryforwards. The Company's franchise tax returns in Texas remain subject to examination for 2017 2018 and after. The Company currently believes that all significant filing positions are

highly certain and that all of its significant income tax filing positions and deductions would be sustained upon audit. Therefore, the Company has no significant reserves for uncertain tax positions and no adjustments to such reserves were required by GAAP. No interest or penalties have been levied against the Company and none are anticipated; therefore, no interest or penalty has been included in our provision for income taxes in the statements Statements of operations. Operations.

Three-Stream Reporting - Beginning July 1, 2022, the Company began reporting volumes and revenues on a three-stream basis, separately reporting crude oil, natural gas, and natural gas liquids ("NGLs") NGL sales. For periods prior to July 1, 2022, sales and reserve volumes, prices, and revenues for NGLs were presented with natural gas. This represents a change in our accounting and reporting presentation necessitated by a change in the underlying facts and circumstances surrounding the Stronghold Acquisition, as Stronghold has historically reported its revenues on a three-stream basis. As clarified in the interpretive guidance of ASC 250, such changes should not be applied on a retrospective basis. Accordingly, we began reporting on a three-stream basis prospectively, beginning July 1, 2022. See Note 5 — ACQUISITIONS & DIVESTITURES for a discussion of the Stronghold Acquisition.

Leases - The Company accounts for its leases in accordance with ASU 2016-02, Leases (Topic 842), effective January 1, 2019. The Company made accounting policy elections to not capitalize leases with a lease term of twelve months or less (i.e., short term short-term leases) and to not separate lease and non-lease components for all asset classes. The Company also elected to adopt the package of practical expedients within ASU 2016-02 that allows an entity to not reassess prior to the effective date (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases, or (iii) initial direct costs for any existing leases and the practical expedient regarding land easements that exist prior to the adoption of ASU 2016-02. The Company did not elect the practical expedient of hindsight when determining the lease term of existing contracts at the effective date.

Earnings (Loss) Per Share – Basic earnings (loss) per share is computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the year. Diluted earnings (loss) per share are calculated to give effect to potentially issuable dilutive common shares.

Major Customers Purchasers – During the year ended December 31, 2023, sales to three purchasers represented 66%, 12%, and 10%, respectively, of total oil, natural gas, and natural gas liquids sales. As of December 31, 2023, sales outstanding from these three purchasers represented 65%, 11%, and 8%, respectively, of accounts receivable. During the year ended December 31, 2022, sales to three customers purchasers represented 68%, 13%, and 5%, respectively, of total oil, natural gas and natural gas liquids sales. As of December 31, 2022, sales outstanding from these three customers purchasers represented 69%, 7%, and 10%, respectively, of accounts receivable. During the year ended December 31, 2021, sales to three customers purchasers represented 76%, 7%, and 6%, respectively, of total oil and natural gas sales. As of December 31, 2021, sales outstanding from these three customers purchasers represented 75%, 8%, and 4%, respectively, of accounts receivable. During the year ended December 31, 2020, sales to three customers represented 68%, 10% and 8%, respectively, of total oil and natural gas sales. As of December 31, 2020, sales outstanding from these three customers represented 80%, 0% and 5%, respectively, of accounts receivable.

Share-Based Employee Compensation – The Company has outstanding stock option grants and restricted stock unit awards to directors, officers and employees, which are described more fully below in "Note 13 - 12 — EMPLOYEE STOCK OPTIONS, RESTRICTED STOCK AWARD PLAN, AND 401(K)". The Company recognizes the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award and recognizes the related compensation expense over the period during which an employee is required to provide service in exchange for the award, which is generally the vesting period.

Share-Based Compensation to Non-Employees – The Company accounts for share-based compensation issued to non-employees as either the fair value of the consideration received or the fair value of the equity instruments issued, whichever is more reliably measurable. The measurement date for these issuances is the earlier of (i) the date at which a commitment for performance by the recipient to earn the equity instruments is reached or (ii) the date at which the recipient's performance is complete.

Share-based***Share-Based Compensation*** - The following table summarizes the Company's share-based compensation, included with General and administrative expense within our Statements of Operations, incurred for the years ended December 31, 2022December 31, 2023, 2021, 2022, and 2020 was $7,162,231, $2,418,323, and $5,364,162, respectively. 2021.

	For the Years Ended December 31,		
	2023	2022	2021
Share-based compensation	$8,833,425	$7,162,231	$2,418,323

Derivative Instruments and Hedging Activities – The Company may periodically enter enters into derivative contracts to manage its exposure to commodity price risk. These derivative contracts, which are generally placed with major financial institutions, may take the form of forward contracts, futures contracts, swaps or options. The oil and gas reference prices upon which the commodity derivative contracts are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company for its oil and natural gas production.

As the Company has not designated its derivative instruments as hedges for accounting purposes, any gains or losses resulting from changes in fair value of outstanding derivative financial instruments and from the settlement of derivative financial instruments are recognized in earnings and included as a component of other income (expense) in the Statements of Operations.

When applicable, the Company records all derivative instruments, other than those that meet the normal purchases and sales exception, on the balance sheet as either an asset or liability measured at fair value. Changes in fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Refer to "Note 8 - 7 — DERIVATIVE FINANCIAL INSTRUMENTS" for further details. additional information.

The Company uses the indirect method of reporting operating cash flows within the Statements of Cash Flows. Accordingly, the non-cash, unrealized gains and losses from derivative contracts are reflected as an adjustment to arrive at Net cash provided by operating activities. The total Gain (loss) on derivative contracts less the Cash received (paid) for derivative settlements, net represents the unrealized (mark to market) gain or loss on derivative contracts.

Recently Adopted Accounting Pronouncements – In August 2018, the FASB issued ASU 2018-13, *Fair Value Measurement (Topic 820): Changes to the Disclosure Requirements for Fair Value Measurement ("ASU 2018-13").* ASU

2018-13 eliminates, adds and modifies certain disclosure requirements for fair value measurement. ASU 2018-13 is became effective for annual and interim periods beginning January 1, 2020, with early adoption permitted for either the entire standard or only the provisions that eliminate or modify requirements. . ASU 2018-13 requires that the additional disclosure requirements be adopted using a retrospective approach. The adoption of this guidance did not have a material impact on the Company's financial statements.

In June 2016, the FASB issued ASU No. 2016-13, Financial Instruments-Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, followed by other related ASUs that provided targeted improvements (collectively "ASU 2016-13"). ASU 2016-13 provides financial statement users with more decision-useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. The guidance is to be applied using a modified retrospective method and is became effective for fiscal years beginning after December 15, 2019, with early adoption permitted. . The Company adopted ASU 2016-13 on January 1, 2020. The adoption of ASU 2016-13 did not have a material impact to the Company's financial statements or disclosures.

In December 2019, the FASB released ASU No. 2019-12 ("ASU 2019-12"), *Income Taxes* (Topic 740) – Simplifying the Accounting for Income Taxes, which removes certain exceptions for recognizing deferred taxes for investments, performing intraperiod allocation and calculating income taxes in interim periods. The ASU also adds guidance to reduce complexity in certain areas, including recognizing deferred taxes for tax goodwill and allocating taxes to members of a consolidated group. The amended standard is became effective for fiscal years beginning after December 15, 2020. The adoption of ASU 2019-12 did not have a material impact to the Company's financial statements or disclosures.

In October 2020, the FASB issued ASU 2020-10, *Codification Improvements* ("ASU 2020-10"), which clarifies or improves disclosure requirements for various topics to align with SEC regulations. This update was effective for the Company beginning in the first quarter of 2021 and is being was applied retrospectively. The adoption and implementation of this ASU did not have a material impact on the Company's financial statements.

In August 2020, the FASB issued ASU No. 2020-06, "Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40)" ("ASU 2020-06"). ASU 2020-06 was issued to reduce the complexity associated with accounting for certain financial instruments with characteristics of liabilities and equity. The guidance may be applied using either a modified retrospective or a fully retrospective method. ASU 2020-06 is became effective for fiscal years beginning after December 15, 2021, with early adoption permitted. . The Company adopted ASU 2020-06 effective January 1, 2022. The adoption and implementation of this ASU did not have a material impact on the Company's financial statements.

In October 2021, the FASB issued ASU 2021-08, "*Business Combinations (Topic 805) – Accounting for Contract Assets and Contract Liabilities from Contracts with Customers"* ("ASU 2021-08"). This update requires the acquirer in a business combination to record contract asset and liabilities following Topic 606 – "Revenue from Contracts with Customers" at acquisition as if it had originated the contract, rather than at fair value. This update became effective for public business entities beginning after December 15, 2022. The

Company adopted ASU 2021-08 effective January 1, 2023. The adoption and implementation of this ASU did not have a material impact on the Company's financial statements, as its revenue is recognized when control transfers to the purchaser at the point of delivery, and no contract liabilities or assets are recognized in accordance with ASC 606.

In July 2023, the FASB issued ASU 2023-03, *Presentation of Financial Statements (Topic 205), Income Statement - Reporting Comprehensive Income (Topic 220), Distinguishing Liabilities from Equity (Topic 480), Equity (Topic 505), and Compensation - Stock Compensation (Topic 718): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 120, SEC Staff Announcement at the March 24, 2022 EITF Meeting, and Staff Accounting Bulletin Topic 6.B, Accounting Series Release 280 - General Revision of Regulation S-X: Income or Loss Applicable to Common Stock*. The ASU provided updated views from the SEC Staff on employee and non-employee share-based payment accounting, including guidance related to spring-loaded awards. As the ASU did not provide any new ASC guidance, and there was no transition or effective date provided, the Company adopted this standard upon issuance, and the adoption did not have a material impact on the Company's financial statements.

Recent Accounting Pronouncements – In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting* ("ASU 2020-04"), which provides provided optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships, subject to meeting certain criteria, that reference referenced LIBOR ("London Inter-Bank Offered Rate") or another rate that is expected to be discontinued. rate. ASU 2020-04 will be was in effect through December 31, 2022. In January 2021, the FASB issued ASU No. 2021-01, *Reference Rate Reform (Topic 848): Scope* ("ASU 2021-01"), to provide clarifying guidance regarding the scope of Topic 848. ASU 2020-04 was issued to provide optional guidance for a limited period of time to ease the potential burden in accounting for (or recognizing the

effects of) reference rate reform on financial reporting. In December 2022, the FASB issued ASU 2022-06, "*Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848*" ("ASU 2022-06"), which defers the sunset date of Topic 848 from December 31, 2022 to December 31, 2024. Beginning August 31, 2022, under the Company's Second Amended and Restated Credit Agreement, the Company's interest rates were transitioned from the LIBOR to the SOFR (Standard Overnight Financing Rate) reference rate. At this time, the Company does not plan to enter into additional contracts using LIBOR as a reference rate.

In October 2021, 2023, the FASB issued ASU 2021-08, 2023-06, "*Business Combinations Disclosure Improvements: Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative*." This update modifies the disclosure or presentation requirements of a variety of Topics in the Codification, which should be applied prospectively. For instance, within ASC 230-10 Statement of Cash Flows - Overall, the amendment requires an accounting policy disclosure in annual periods of where cash flows associated with their derivative instruments and their related gains and losses are presented in the statement of cash flows. Additionally, within ASC 260-10 Earnings Per Share - Overall, the amendment requires disclosure of the methods used in the diluted earnings-per-share computation for each dilutive security and clarifies that certain disclosures should be made during interim periods. The Company is currently assessing the impact of this update on its financial statements and related notes. If by June 30, 2027, the SEC has not removed the applicable requirement from Regulation S-X or Regulation S-K, the pending content of the related amendment will be removed from the Codification and will not become effective for any entity.

In November 2023, the FASB issued ASU 2023-07 "*Segment Reporting (Topic 805) – Accounting for Contract Assets and Contract Liabilities from Contracts with Customers" 280): Improvements to Reportable Segment Disclosures* (."ASU 2021-08"). This update requires that a public entity with multiple reportable segments disclose significant segment expenses that are regularly provided to the acquirer chief operating decision maker ("CODM"), as well as other segment items that are included in the calculation of segment profit or loss. A public entity will also be required to disclose all annual disclosures about a business combination reportable segment's profit or loss currently required by Topic 280 in interim periods. Although a public entity is permitted to record contract asset disclose multiple measures of a segment's profit or loss, at least one of the reported segment profit or loss measures should be consistent with the measurement principles used in measuring the corresponding amounts of the public entity's consolidated financial statements. Further, a public entity must disclose the title and liabilities following position of the CODM as well as how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources. Finally, the update requires that a public entity that has a single reportable segment provide all the disclosures required by the amendments in this update and all existing segment disclosures in Topic 606 – "Revenue from Contracts with Customers" at 280. The Company is currently assessing the impact of adopting this new guidance on its financial disclosures. The amendments in this update are effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024.

acquisition as if it had originated In December 2023, the contract, rather than at fair value. This FASB issued ASU 2023-09 "*Income Taxes (Topic 740): Improvements to Income Tax Disclosures.*" The amendments from this update is effective provide for more transparency about income tax information through improvements to income tax disclosures primarily related to the rate reconciliation and income taxes paid information. Specifically, public business entities beginning after December 15, 2022 are required to disclose a tabular reconciliation, using both percentages and reporting currency amounts, showing detail from eight specific categories: (a) state and local income tax net of federal (national) income tax effect, (b) foreign tax effects, (c) effect of changes in tax laws or rates enacted in the current period, (d) effect of cross-border tax laws, (e) tax credits, (f) changes in valuation allowances, (g) nontaxable or nondeductible items, and (h) changes in unrecognized tax benefits. In addition, public business entities are required to separately disclose any reconciling item, disaggregated by nature and/or jurisdiction, in which the effect of the reconciling item is equal to or greater than five percent of the amount computed by multiplying the income (or loss) from continuing operations before income taxes by the applicable statutory income tax rate. Also, for the state and local category, a public business entity is required to provide a qualitative description of the states and local jurisdictions that make up the majority (greater than 50 percent) of the category. Further, the amount of income taxes paid (net of refunds received) are required to be disaggregated by (i) federal (national), with early adoption permitted. state, and foreign taxes, and (ii) by individual jurisdictions in which income taxes paid (net of refunds received) is equal to or greater than five percent of total income taxes paid (net of refunds received). Finally, the amendments from this update require that all entities disclose (i) income (or loss) from continuing operations before income tax expense (or benefit) disaggregated between domestic and foreign and (ii) income tax expense (or benefit) from continuing operations disaggregated by federal, state, and foreign. The Company continues to evaluate is currently assessing the provisions impact of adopting this update, but it does not believe the adoption will have a material impact new guidance on its financial position, results of operations or liquidity. disclosures. For public business entities, the amendments in this update are effective for annual periods beginning after December 15, 2024.

NOTE 2 – — REVENUE RECOGNITION

The Company predominantly derives its revenue from the sale of produced crude oil, natural gas, and natural gas. NGLs. The contractual performance obligation is satisfied when the product is delivered to the customer. purchaser. Revenue is recorded in the month the product is delivered to the purchaser. The Company receives payment from one to three months after delivery. The Company has utilized the practical expedient in Accounting Standards Codification ("ASC") 606-10-50-14, which states an entity is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's sales contracts, each unit of production delivered to a customer purchaser represents a separate performance obligation, therefore, future volumes to be delivered are wholly unsatisfied and disclosure of transaction price allocated to remaining performance obligation is not required. The transaction price includes variable consideration as product pricing is based on published market prices and adjusted for contract specified differentials such as quality, energy content, and transportation. The guidance does not require that the transaction price be fixed or stated in the contract. Estimating the variable consideration does not require significant judgment and the Company engages third party sources to validate the estimates. Revenue is recognized net of royalties due to third parties in an amount that reflects the consideration the Company expects to receive in exchange for those products.

Oil sales

Under the Company's oil sales contracts, the Company sells oil production at the point of delivery and collects an agreed upon index price, net of pricing differentials. The Company recognizes revenue at the net price received when control transfers to the purchaser at the point of delivery and it is probable the Company will collect the consideration it is entitled to receive.

Natural gas and NGL sales

Under the Company's natural gas sales processing contracts for our its Central Basin Platform properties Delaware Basin properties and part a portion of our its Northwest Shelf assets, the Company delivers unprocessed natural gas to a midstream processing entity at the wellhead. The midstream processing entity obtains control of the natural gas and NGLs (natural gas liquids) at the wellhead. The midstream processing entity gathers and processes the natural gas and NGLs and remits proceeds to the Company for the resulting sale of natural gas and NGLs. Under these processing agreements, the Company recognizes revenue when control transfers to the purchaser at the point of delivery and it is probable the Company will collect the consideration it is entitled to receive. As such, the Company accounts for any fees and deductions as a reduction of the transaction price.

Until April 30, 2022, under the Company's natural gas sales processing contracts for the bulk of our Northwest Shelf assets, the Company delivered unprocessed natural gas to a midstream processing entity at the wellhead. However, the Company maintained ownership of the gas through processing and received proceeds from the marketing of the resulting products. Under this processing agreement, the Company recognized the fees associated with the processing as an expense rather than netting these costs against Oil and Natural Gas Revenues in the Statements of Operations. Beginning May 1, 2022, these contracts were combined into one contract, and it was modified so that the Company no longer maintained ownership of the gas through processing. Accordingly, the Company from that point on accounts for any such fees and deductions as a reduction of the transaction price.

There remains only one contract with a natural gas processing entity in place where point of control of gas dictates requiring the fees be recorded as an expense.

Disaggregation of Revenue. The following table presents revenues disaggregated by product:

		For the years ended December 31,		
		2022	2021	2020
	For the years ended December 31,			For the years ended December 31,
	2023		2023	2022	2021
Oil, Natural Gas, and Natural Gas Liquids Revenues	Oil, Natural Gas, and Natural Gas Liquids Revenues			
Oil	Oil	$321,062,672	$181,533,093	$109,113,557
Natural gas		18,693,631	14,772,873	3,911,581
Natural gas liquids		7,493,234	—	—
Oil				
Oil				
Natural gas (1)				
Natural gas liquids (1)				

Total oil, natural gas, and natural gas liquids revenues	Total oil, natural gas, and natural gas liquids revenues	$347,249,537	$196,305,966	$113,025,138

(1) Beginning on July 1, 2022, the Company began reporting volumes and revenues on a three-stream basis, separately reporting crude oil, natural gas, and NGL sales. For periods prior to July 1, 2022, sales revenues for NGLs were presented with natural gas.

NOTE 3 – — LEASES

The Company has operating leases for our its offices in Midland, Texas and The Woodlands, Texas. The Midland office is under a five-year lease which began January 1, 2021. The Midland office lease was amended effective October 1, 2022, with the revised five-year lease ending September 30, 2027. Beginning January 15, 2021, the Company entered into a five-and-a-half-year sub-lease for office space in The Woodlands, Texas; however, effective as of May 31, 2023, The Woodlands office sub-lease was terminated. On May 9, 2023, the Company entered into a 71-month (five years and 11-month) new lease for a larger amount of office space in The Woodlands, Texas. The At the time of the new lease commencement, the additional office space that was added was under construction and until completed, the rental obligation for this space had not yet commenced, because the Company did not have control of the additional office space in accordance with ASC 842-40-55-5. On September 27, 2023, the Company provided a certificate of acceptance of premises to the lessor of the additional office space, and accordingly, the future payments associated for this space are included along with these the other operating leases, are reflected in the future lease payments schedule below.

During the years ended December 31, 2020 and first quarter of 2021, the Company had an operating lease with Arenaco, LLC for its Tulsa, Oklahoma office. The Tulsa lease was terminated as of March 31, 2021, with payments made until the end of February 2021. Refer to "Note 14 - 13 — RELATED PARTY TRANSACTIONS" for further details.

The Company has month to month leases for office equipment and compressors used in our its operations on which the Company has elected to apply ASU 2016-02 (i.e. to not capitalize). The office equipment and compressors are not subject to ASU 2016-02 based on the agreement and nature of use. These leases are for terms that are less than 12 months and the Company does not intend to continue to lease this equipment for more than 12 months. The lease costs associated with these leases is reflected in the short-term lease costs within Lease operating expenses, shown below.

The Company has financing leases for vehicles. These leases have a term of 36 months at the end of which the Company owns the vehicles. These vehicles are generally sold at the end of their term and the proceeds applied to a new vehicle.

Future lease payments associated with these operating and financing leases as of December 31, 2022 December 31, 2023 are as follows:

		2023	2024	2025	2026	2027
	2024					
Operating lease payments (1)	Operating lease payments (1)	$474,464	$482,328	$494,692	$398,096	$216,000
Financing lease payments (2)	Financing lease payments (2)	793,723	727,451	379,421	—	—

2024	2025	2026	2027	2028	Thereafter

(1) The weighted average annual discount rate as of December 31, 2022 December 31, 2023 for operating leases was 4.50%. Based on this rate, the future lease payments above include imputed interest of $193,321. $277,833. The weighted average remaining term of operating leases was 4.29 4.32 years.

(2) The weighted average annual discount rate as of December 31, 2022 December 31, 2023 for financing leases was 5.82% 6.69%. Based on this rate, the future lease payments above include imputed interest of $138,463. $143,869. The weighted average remaining term of financing leases was 2.41 2.00 years.

The following table represents a reconciliation between the undiscounted future cash flows in the table above and the operating and financing lease liabilities disclosed in the Balance Sheets:

	As of December 31,	
	2022	2021
As of December 31,		As of December 31,

	2023	2023	2022
Operating lease liability, current portion	Operating lease liability, current portion	398,362	290,766
Operating lease liability, non-current portion	Operating lease liability, non-current portion	1,473,897	1,138,319
Operating lease liability, total	**Operating lease liability, total**	**1,872,259**	**1,429,085**
Total undiscounted future cash flows (sum of future operating lease payments)	Total undiscounted future cash flows (sum of future operating lease payments)	2,065,580	1,577,786
Imputed interest	Imputed interest	193,321	148,701
Undiscounted future cash flows less imputed interest	**Undiscounted future cash flows less imputed interest**	**1,872,259**	**1,429,085**
Financing lease liability, current portion	Financing lease liability, current portion	709,653	316,514
Financing lease liability, current portion			
Financing lease liability, current portion			
Financing lease liability, non-current portion	Financing lease liability, non-current portion	1,052,479	343,727
Financing lease liability, total	**Financing lease liability, total**	**1,762,132**	**660,241**
Total undiscounted future cash flows (sum of future financing lease payments)	Total undiscounted future cash flows (sum of future financing lease payments)	1,900,595	692,091
Imputed interest	Imputed interest	138,463	31,850
Undiscounted future cash flows less imputed interest	**Undiscounted future cash flows less imputed interest**	**1,762,132**	**660,241**

The following table provides supplemental information regarding cash flows from operations: lease costs in the Statements of Operations:

		2022 2023
Operating lease costs	$	363,908 541,801
Short-term lease costs (1)	$	2,618,405 5,096,723
Financing lease costs:		
Amortization of financing lease assets(2)	$	505,211 803,721
Interest on financing lease liabilities (3)	$	48,472 101,269

(1) Amount included in Lease operating expenses

(2) Amount included in Depreciation, depletion and amortization

(3) Amount included in Interest expense (expense)

NOTE 4 – — EARNINGS (LOSS) PER SHARE INFORMATION

For the years ended December 31,	2022	2021	2020
Net Income (Loss)	$ 138,635,025	$ 3,322,892	$ (253,411,828)
Basic Weighted-Average Shares Outstanding	121,264,175	99,387,028	72,891,310
Effect of dilutive securities:			
Stock options	83,384	75,897	—
Restricted stock units	2,040,181	1,613,810	—
Performance stock units	248,206	—	—
Common warrants	18,118,722	20,116,440	—
Diluted Weighted-Average Shares Outstanding	141,754,668	121,193,175	72,891,310
Basic Earnings (Loss) per Share	$ 1.14	$ 0.03	$ (3.48)
Diluted Earnings (Loss) per Share	$ 0.98	$ 0.03	$ (3.48)

The following table presents the calculation of the Company's basic and diluted earnings per share for the years ended December 31, 2023, 2022 and 2021. For all dilutive securities, the treasury stock method of calculating the incremental shares is applied.

Stock options to purchase 70,500, 113,659, and 465,500 shares of common stock

For the years ended December 31,	2023	2022	2021
Net Income	$ 104,864,641	$ 138,635,025	$ 3,322,892
Basic Weighted-Average Shares Outstanding	190,589,143	121,264,175	99,387,028
Effect of dilutive securities:			
Stock options	—	83,384	75,897
Restricted stock units	1,292,582	2,040,181	1,613,810
Performance stock units	438,818	248,206	—
Common warrants	3,044,307	18,118,722	20,116,440
Diluted Weighted-Average Shares Outstanding	195,364,850	141,754,668	121,193,175
Basic Earnings per Share	$ 0.55	$ 1.14	$ 0.03
Diluted Earnings per Share	$ 0.54	$ 0.98	$ 0.03

The following table presents the securities which were excluded from the Company's computation of diluted earnings (loss) per share during for the years ended December 31, 2022 December 31, 2023, 2021 2022 and 2020, respectively, as their effect would have been anti-dilutive. Also excluded from the computation of diluted earnings per share were 13,512, 20,610, and 2,144,617 shares of unvested restricted stock units during the years ended December 31, 2022, 2021, and 2020, respectively, as their effect would have been anti-dilutive. Unvested performance stock units of 814,255, 94,270, and —

were excluded from the computation of diluted earnings per share during the years ended December 31, 2022, 2021, and 2020, respectively, as their effect would have been anti-dilutive. Common warrants to purchase 29,804,300 shares of common stock were excluded from the computation of diluted earnings per share during the year ended December 31, 2020, as their effect would have been anti-dilutive.

Pre-funded warrants to purchase 13,428,500 shares of common stock were included in the calculation of the Basic Weighted-Average Shares Outstanding for the year ended December 31, 2020 as they were exercisable for a nominal amount and so were treated as if they were exercised at issuance. These shares were exercised in January 2021 and were included in the beginning shares outstanding for the calculation of Basic Weighted-Average Shares Outstanding for the year ended December 31, 2021.

	2023	2022	2021
Antidilutive securities:			
Stock options to purchase common stock	264,966	70,500	113,659
Unvested restricted stock units	56,153	13,512	20,610
Unvested performance stock units	1,445,804	814,255	94,270

NOTE 5 – — ACQUISITIONS & DIVESTITURES

Andrews County Acquisition Sale and Exchange

The Company entered into a Purchase, Sale and Exchange Agreement dated February 1, 2021, effective January 1, 2021, with an unrelated party, covering the sale and exchange of certain oil and gas interests in Andrews County, Texas. Upon the sale and transfer of wells and leases between the two parties, closing, the Company received a cash consideration of $2,000,000 and reduced the Company's asset retirement obligations by $2,934,126 for the properties sold and added $662,705 of asset retirement obligations for the wells acquired.

Stronghold Acquisition

On July 1, 2022, Ring, as buyer, and Stronghold Energy II Operating, LLC, a Delaware limited liability company ("Stronghold OpCo") and Stronghold Energy II Royalties, LP, a Delaware limited partnership ("Stronghold RoyaltyCo", together with Stronghold OpCo, collectively, "Stronghold"), as seller, entered into a purchase and sale agreement (the "Purchase Agreement"). Pursuant to the Purchase Agreement, Ring acquired (the "Stronghold Acquisition") interests in oil and gas leases and related property of Stronghold consisting of approximately 37,000 net acres located in the Central Basin Platform of the Texas Permian Basin. On August 31, 2022, Ring completed the Stronghold Acquisition.

The fair value of consideration paid to Stronghold was approximately $394.0 million, of which $165.9 million, net of customary purchase price adjustments, was paid in cash at closing, $15.0 million will be was payable in cash after the six-month anniversary of the closing date of the Stronghold Acquisition. Shortly after closing, approximately $4.5 million was paid for inventory and vehicles and approximately $1.8 million was paid for August oil derivative settlements for certain novated hedges. The cash portion of the consideration was funded primarily from borrowings under a new fully committed revolving credit facility (the "Credit Facility") underwritten by Truist Securities, Citizens Bank, N.A., KeyBanc Capital Markets Inc., and Mizuho Bank, Ltd. The borrowing base of the $1.0 billion Credit Facility was increased from $350.0 million to $600.0 $600 million at the closing of the Stronghold Acquisition. The remaining consideration consisted of 21,339,986 shares of Ring common stock and 153,176 shares of newly created Series A Convertible Preferred Stock, par value $0.001 ("Preferred Stock") which was converted into 42,548,892 shares of common stock on October 27, 2022. Please see "Note 12 - 11 — STOCKHOLDERS' EQUITY" for further discussion. In addition, Ring assumed $24.8 million of derivative liabilities, $1.7 million of items in suspense and $14.5 million in asset retirement obligations.

Purchase Price Allocation

The Stronghold Acquisition has been was accounted for as an asset acquisition in accordance with ASC Topic 805 - Business Combinations. The fair value of the consideration paid by Ring and allocation of that amount to the underlying assets acquired, on a relative fair value basis, was recorded on Ring's books as of the date of the closing of the Stronghold Acquisition. Additionally, costs directly related to the Stronghold Acquisition were capitalized as a component of the purchase price. Determining the fair value of the assets and liabilities acquired requires required judgment and certain assumptions to be made, the most significant of these being related to the valuation of Stronghold's oil and gas properties. The inputs and assumptions related to the oil and gas properties are were categorized as level 3 in the fair value hierarchy.

The following table represents the preliminary final allocation of the total cost of the Stronghold Acquisition to the assets acquired and liabilities assumed as of the Stronghold Acquisition date:

Consideration:		
Shares of Common Stock issued		21,339,986
Common Stock price as of August 31, 2022	$	3.24
Common Stock Consideration	$	69,141,555
Shares of Preferred Stock issued		153,176
Aggregate Liquidation Preference	$	153,176,000
Conversion Price	$	3.60
As-Converted Shares of Common Stock		42,548,892
Common Stock Price as of August 31, 2022	$	3.24
Preferred Stock Consideration	$	137,858,446
Cash consideration:		
Closing amount paid to Stronghold		121,392,455
Escrow deposit paid		46,500,000
Cash paid for inventory and fixed assets		4,527,103
Cash paid for realized losses on August oil derivatives		1,777,925
Cash received for post-close adjustments, net		(5,535,839)
Total cash consideration		168,661,644
Fair value of deferred payment liability		14,807,276
Post-close settlement to be paid to Stronghold		3,511,170
Fair value of consideration paid to seller		393,980,091
Direct transaction costs		9,162,143
Total consideration	$	403,142,234
Fair value of assets acquired:		
Oil and natural gas properties		439,589,683
Inventory and fixed assets		4,527,103
Amount attributable to assets acquired	$	444,116,786
Fair value of liabilities assumed:		
Suspense liability		1,651,596
Derivative liabilities, marked to market		24,784,406
Asset retirement obligations		14,538,550
Amount attributable to liabilities assumed	$	40,974,552
Net assets acquired	$	403,142,234

Approximately $40.4 million of revenues and $13.6 million of direct operating expenses attributed to the Stronghold Acquisition are were included in the Company's Statements of Operations for the period from September 1, 2022 through December 31, 2022.

Delaware Basin Divestiture

NOTE 6 – DEPOSIT FORFEITURE INCOME

In the second quarter of 2020, On May 11, 2023, the Company entered into an agreement with an intended buyer to sell completed the Company's divestiture of its Delaware Basin assets. assets to an unaffiliated party for $8.3 million. The agreement sale had an effective date of March 1, 2023. The final cash consideration was amended on six different occasions throughout 2020 releasing approximately $7.6 million. As part of the initial deposits to the Company and requiring additional non-refundable deposits. In total, $5,500,000 in non-refundable deposits were made to the Company. In October 2020, the agreement was terminated as divestiture, the buyer was not able to consummate the transaction. As such, the Company recognized the $5,500,000 as income in its Statements assumed an asset retirement obligation balance of Operations as no divestiture of assets had occurred. Refer to "Note 17 - LEGAL MATTERS" for further details. approximately $2.3 million.

Founders Acquisition

On July 10, 2023, the Company, as buyer, and Founders Oil & Gas IV, LLC ("Founders"), as seller, entered into an Asset Purchase Agreement (the "Founders Purchase Agreement"). Pursuant to the closing of the Purchase Agreement, on August 15, 2023 the Company acquired (the "Founders Acquisition") interests in oil and gas leases and related property of Founders located in the Central Basin Platform of the Texas Permian Basin in Ector County, Texas, for a purchase price (the "Purchase Price") of (i) a cash deposit of $7.5 million paid on July 11, 2023 into a third-party escrow account as a deposit pursuant to the Founders Purchase Agreement, (ii) approximately $42.5 million in cash paid on the closing date, net of approximately $10 million of preliminary and customary purchase price adjustments with an effective date of April 1, 2023, and (iii) a deferred cash payment of approximately $11.9 million paid on December 18, 2023, net of customary purchase price adjustments.

The Founders Acquisition has been accounted for as an asset acquisition in accordance with ASC 805. The fair value of the consideration paid by Ring and allocation of that amount to the underlying assets acquired, on a relative fair value basis, was recorded on Ring's books as of the date of the closing of the Founders Acquisition. Additionally, costs directly related to the Founders Acquisition were capitalized as a component of the purchase price. Determining the fair value of the assets and liabilities acquired required judgment and certain assumptions to be made, the most significant of these being related to the valuation of Founder's oil and gas properties. The inputs and assumptions related to the oil and gas properties are categorized as level 3 in the fair value hierarchy.

The following table represents the final allocation of the total cost of the Founders Acquisition to the assets acquired and liabilities assumed as of the Founders Acquisition date:

Consideration:		
Cash consideration		
Escrow deposit released at closing	$	7,500,000
Closing amount paid to Founders		42,502,799
Interest from escrow deposit		1,747
Fair value of deferred payment liability		14,657,383
Post-close adjustments		(4,139,244)
Total cash consideration	$	60,522,685
Direct transaction costs		1,361,843
Total consideration	**$**	**61,884,528**
Fair value of assets acquired:		
Oil and natural gas properties	$	64,886,472
Amount attributable to assets acquired	$	64,886,472
Fair value of liabilities assumed:		
Suspense liability	$	677,116
Asset retirement obligations		2,090,777
Ad valorem tax liability		234,051
Amount attributable to liabilities assumed	$	3,001,944
Net assets acquired	**$**	**61,884,528**

Approximately $18.0 million of revenues and $5.0 million of direct operating expenses attributed to the Founders Acquisition are included in the Company's Statements of Operations for the period from August 16, 2023 through December 31, 2023.

New Mexico Divestiture

On September 27, 2023, the Company completed the divestiture of its operated New Mexico assets to an unaffiliated party for $4.5 million, resulting in preliminary cash consideration of approximately $3.7 million, subject to customary final purchase price adjustments. The sale had an effective date of June 1, 2023. As part of the divestiture, the buyer assumed an asset retirement obligation balance of approximately $2.4 million.

Gaines County Texas Sale

On December 29, 2023, the Company completed the sale of specified oil and gas properties within Gaines County, Texas to an unaffiliated party for $1.5 million, which resulted in cash proceeds of $1.4 million, net of $0.1 million in commission fees. The sale had an effective date of December 1, 2023. As part of the sale, the buyer assumed an asset retirement obligation balance of approximately $0.5 million.

NOTE 7 – 6 — OIL AND NATURAL GAS PRODUCING ACTIVITIES

Set forth below is certain information regarding the aggregate capitalized costs of oil and natural gas properties and costs incurred by the Company for its oil and natural gas property acquisitions, development and exploration activities:

Net Capitalized Costs

As of December 31,		2022		2021
Oil and natural gas properties, full cost method	$	1,463,838,595	$	883,844,745
Financing lease asset subject to depreciation		3,019,476		1,422,487
Fixed assets subject to depreciation		3,147,125		2,089,722
Total Properties and Equipment		1,470,005,196		887,356,954
Accumulated depletion, depreciation and amortization		(289,935,259)		(235,997,307)
Net Properties and Equipment	$	1,180,069,937	$	651,359,647

As of December 31,		2023		2022
Oil and natural gas properties, full cost method				
Proved properties		1,663,548,249		1,463,838,595
Unproved properties		—		—
Total oil and natural gas properties, full cost method		1,663,548,249		1,463,838,595
Accumulated depletion of oil and natural gas properties		(373,280,583)		(287,052,595)
Net oil and natural gas properties capitalized	$	1,290,267,666	$	1,176,786,000

Net Costs Incurred in Oil and Gas Producing Activities

For the years Ended December 31,		2022		2021
Payments for the Stronghold Acquisition	$	177,823,787	$	—
Payments to purchase oil and natural gas properties		1,563,703		1,368,437
Proceeds from divestiture of oil and natural gas properties		(23,700)		(2,000,000)
Payments to develop oil and natural gas properties		129,332,155		51,302,131
Payments to acquire or improve fixed assets subject to depreciation		319,945		568,832
Sale of fixed assets subject to depreciation	$	(134,600)	$	—
Total Net Costs Incurred	$	308,881,290	$	51,239,400

For the years Ended December 31,		2023		2022		2021
Payments to acquire oil and natural gas properties	$	82,900,900	$	179,387,490	$	1,368,437
Payments to explore oil and natural gas properties		—		—		—
Payments to develop oil and natural gas properties		152,559,314		129,332,155		51,302,131
Total costs incurred	$	235,460,214	$	308,719,645	$	52,670,568

NOTE 8 – 7 — DERIVATIVE FINANCIAL INSTRUMENTS

The Company is exposed to fluctuations in crude oil and natural gas prices on its production. It utilizes derivative strategies that consist of either a single derivative instrument or a combination of instruments to manage the variability in cash flows associated with the forecasted sale of our future domestic oil and natural gas production. While the use of derivative instruments may limit or partially reduce the downside risk of adverse commodity price movements, their use also may limit future income from favorable commodity price movements.

From time to time, the Company enters into derivative contracts to protect the Company's cash flow from price fluctuation and maintain its capital programs. The Company has historically used either costless collars, deferred premium puts, or swaps for this purpose. Oil derivative contracts are based on WTI Crude Oil crude oil prices and natural gas contacts are based on the Henry Hub or Waha Hub. A "costless collar" is the combination of two options, a put option (floor) and call option (ceiling) with the options structured so that the premium paid for the put option will be offset by the premium received from selling the call option. Similar to costless collars, there is no cost to enter into the swap contracts. On swap contracts, there is no spread and payments will be made or received based on the difference between WTI and the swap contract price. The A deferred premium put contract has the premium established upon entering the contract, and due upon settlement of the contract.

The use of derivative transactions involves the risk that the counterparties, which generally are financial institutions, will be unable to meet the financial terms of such transactions. All of our derivative contracts have been are with lenders under our credit facility. Credit Facility. Non-performance risk is incorporated in the discount rate by adding the quoted bank (counterparty) credit default swap (CDS) rates to the risk free rate. Beginning September 1, Although the Company assumed counterparties hold the derivative liabilities (novated hedges) associated with its acquisition of right to offset (i.e. netting) the Stronghold assets (see "Note 5 - ACQUISITIONS & DIVESTITURES"), which are subject to master netting agreements. Additional derivative contracts settlement amounts with the same counterparty are also subject to netting. Still, Company, in accordance with ASC 815-10-50-4B, the Company continues to classify classifies the fair value of all its derivative positions on a gross basis in its corresponding Balance Sheets.

The Company’s derivative financial instruments are recorded at fair value and included as either assets or liabilities in the accompanying Balance Sheets. The Company has not designated its derivative instruments as hedges for accounting purposes, and, as a result, any gains or losses resulting from changes in fair value of outstanding derivative financial instruments and from the settlement of derivative financial instruments are recognized in earnings and included as a component of "Other Income (Expense)" under the heading "Gain (loss) on derivative contracts" in the accompanying Statements of Operations.

The following presents the impact of the Company’s contracts on its balance sheets Balance Sheets for the periods indicated.

	As of December 31,	As of December 31,	
	2023	2023	2022
Commodity derivative instruments, marked to market:			
		As of December 31,	
Derivative assets, current			
		2022	2021
Commodity derivative instruments, marked to market:			
Derivative assets, current			
Derivative assets, current	Derivative assets, current	16,193,327	—
Discounted deferred premiums	Discounted deferred premiums	(11,524,165)	—
Derivatives assets, current, net of premiums	**Derivatives assets, current, net of premiums**	**$ 4,669,162**	**$ —**
Derivative assets, noncurrent	Derivative assets, noncurrent	7,606,258	—
Derivative assets, noncurrent			
Derivative assets, noncurrent			
Discounted deferred premiums	Discounted deferred premiums	(1,476,848)	—
Derivative assets, noncurrent, net of premiums	**Derivative assets, noncurrent, net of premiums**	**$ 6,129,410**	**$ —**
Derivative liabilities, current	**Derivative liabilities, current**	**$13,345,619**	**$29,241,558**
Derivative liabilities, current			
Derivative liabilities, current			

Derivative liabilities, noncurrent	Derivative liabilities, noncurrent	$10,485,650	$	—
Derivative liabilities, noncurrent				
Derivative liabilities, noncurrent				

The components of “Gain (loss) on derivative contracts” from the Statements of Operations are as follows for the respective periods:

		For the years ended December 31,		
		2022	2021	2020
	For the years ended December 31,			
	2023	2023	2022	2021
Oil derivatives:	Oil derivatives:			
Realized gain (loss) on oil derivatives		$(61,875,870)	$(53,511,332)	$22,522,591
Realized loss on oil derivatives				
Realized loss on oil derivatives				
Realized loss on oil derivatives				
Unrealized gain (loss) on oil derivatives	Unrealized gain (loss) on oil derivatives	40,546,123	(24,143,120)	(2,164,779)
Gain (loss) on oil derivatives		$(21,329,747)	$(77,654,452)	$20,357,812
Loss on oil derivatives				
Natural gas derivatives:	Natural gas derivatives:			
Natural gas derivatives:				
Natural gas derivatives:				
Realized gain (loss) on natural gas derivatives				
Realized gain (loss) on natural gas derivatives				
Realized gain (loss) on natural gas derivatives	Realized gain (loss) on natural gas derivatives	(650,084)	743,178	—
Unrealized gain (loss) on natural gas derivatives	Unrealized gain (loss) on natural gas derivatives	447,172	(941,867)	1,008,256
Gain (loss) on natural gas derivatives	**Gain (loss) on natural gas derivatives**	$ (202,912)	$ (198,689)	$ 1,008,256
Gain (loss) on derivative contracts	**Gain (loss) on derivative contracts**	$(21,532,659)	$(77,853,141)	$21,366,068

Gain (loss) on derivative contracts

Gain (loss) on derivative contracts

The components of “Cash (paid) received for derivative settlements, net” within the Statements of Cash Flows are as follows for the respective periods:

	For the years ended December 31,		
	2022	2021	2020
Cash flows from operating activities			
Cash (paid) received on oil derivatives	$ (61,875,870)	$ (53,511,332)	$ 22,522,591
Cash (paid) received on natural gas derivatives	(650,084)	743,178	—
Cash (paid) received from derivative settlements	$ (62,525,954)	$ (52,768,154)	$ 22,522,591

	For the years ended December 31,		
	2023	2022	2021
Cash flows from operating activities			
Cash paid for oil derivatives	$ (11,364,484)	$ (61,875,870)	$ (53,511,332)
Cash (paid) received on natural gas derivatives	2,279,564	(650,084)	743,178
Cash paid for derivative settlements, net	$ (9,084,920)	$ (62,525,954)	$ (52,768,154)

The following tables reflect the details of current derivative contracts as of December 31, 2022 December 31, 2023 (Quantities are in barrels (Bbl) for the oil derivative contracts and in million British thermal units (MMBtu) for the natural gas derivative contracts.) contracts):

		Oil Hedges (WTI)	
		2023	2024
	Q1 2024		
Swaps:	**Swaps:**		
Swaps:			
Swaps:			
Hedged volume (Bbl)			
Hedged volume (Bbl)			
Hedged volume (Bbl)	Hedged volume (Bbl)	389,250	894,000
Weighted average swap price	Weighted average swap price	$ 77.55	$ 66.94
Deferred premium puts:	**Deferred premium puts:**		
Deferred premium puts:			
Deferred premium puts:			
Hedged volume (Bbl)			
Hedged volume (Bbl)			
Hedged volume (Bbl)	Hedged volume (Bbl)	773,500	91,000

Oil Hedges (WTI)				Oil Hedges (WTI)			
Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025

Weighted average strike price	Weighted average strike price	$ 90.64	$ 83.75
Weighted average deferred premium price	Weighted average deferred premium price	$ 15.25	$ 17.32
Two-way collars:	**Two-way collars:**		

Two-way collars:

Two-way collars:

Hedged volume (Bbl)

Hedged volume (Bbl)

Hedged volume (Bbl)	Hedged volume (Bbl)	487,622	475,350
Weighted average put price	Weighted average put price	$ 52.16	$ 67.88
Weighted average call price	Weighted average call price	$ 62.94	$ 83.32
Three-way collars:			
Hedged volume (Bbl)		66,061	—
Weighted average first put price		$ 45.00	$ —
Weighted average second put price		$ 55.00	$ —
Weighted average call price		$ 80.05	$ —

	Gas Hedges (Henry Hub)	
	2023	2024

	Gas Hedges (Henry Hub)						Gas Hedges (Henry Hub)	
Q1 2024	Q1 2024	Q2 2024	Q3 2024	Q4 2024	Q1 2025	Q2 2025	Q3 2025	Q4 2025

NYMEX Swaps:	**NYMEX Swaps:**		

NYMEX Swaps:

NYMEX Swaps:

Hedged volume (MMBtu)

Hedged volume (MMBtu)

Hedged volume (MMBtu)	Hedged volume (MMBtu)	159,890	552,000
Weighted average swap price	Weighted average swap price	$ 2.40	$ 4.61
Two-way collars: (1)			

Two-way collars:

Two-way collars:

Two-way collars:

Hedged volume (MMBtu)

Hedged volume (MMBtu)

Hedged volume (MMBtu)	Hedged volume (MMBtu)	2,258,317	1,712,250
Weighted average put price	Weighted average put price	$ 3.18	$ 4.00
Call hedged volume (MMBtu)		2,140,317	1,712,250
Weighted average call price	Weighted average call price	$ 4.89	$ 6.29

Weighted average call price

Weighted average call price

	Gas Hedges (basis differential)	
	2023	**2024**
Waha basis swaps:		
Hedged volume (MMBtu)	1,339,685	—
Weighted average swap price	(2)	$ —

	Oil Hedges (basis differential)							
	Q1 2024	**Q2 2024**	**Q3 2024**	**Q4 2024**	**Q1 2025**	**Q2 2025**	**Q3 2025**	**Q4 2025**
Argus basis swaps:								
Hedged volume (Bbl)	240,000	364,000	368,000	368,000	270,000	273,000	276,000	276,000
Weighted average spread price (1)	$ 1.15	$ 1.15	$ 1.15	$ 1.15	$ 1.00	$ 1.00	$ 1.00	$ 1.00

(1) The two-way collars for oil basis swap hedges are calculated as the first quarter fixed price (weighted average spread price above) less the difference between WTI Midland and WTI Cushing, in the issue of 2023 include 2x1 collars where the put volumes of 236,000 are two times the call volumes of 118,000. Argus Americas Crude.

(2) The WAHA basis swaps in place for the calendar year of 2023 consist of two derivative contracts, each with a fixed price of the Henry Hub natural gas price less a fixed amount (weighted average of $0.55 per MMBtu).

NOTE 9 – 8 — FAIR VALUE MEASUREMENTS

Fair value is 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 authoritative guidance requires disclosure of the framework for measuring fair value and requires that fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs that are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy. We continue to evaluate our inputs to ensure the fair value level classification is appropriate. When transfers between levels occur, it is our policy to assume that the transfer occurred at the date of the event or change in circumstances that caused the transfer.

The fair values of the Company's derivatives are not actively quoted in the open market. The Company uses a market approach to estimate the fair values of its derivative instruments on a recurring basis, utilizing commodity futures pricing for the underlying commodities provided by a reputable third party, a Level 2 fair value measurement.

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments if events or changes in certain circumstances indicate that adjustments may be necessary.

The following table summarizes the valuation of our assets and liabilities that are measured at fair value on a recurring basis (further detail in "Note 8 -7 — DERIVATIVE FINANCIAL INSTRUMENTS").

	Fair Value Measurement Classification		Fair Value Measurement Classification			
	Quoted prices in Active Markets for Identical Assets or (Liabilities) (Level 1)		Quoted prices in Active Markets for Identical Assets or (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of December 31, 2022						
	Fair Value Measurement Classification					
Commodity Derivatives - Assets						

	Quoted prices in Active Markets for Identical Assets or (Liabilities) (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
As of December 31, 2021				
Commodity Derivatives - Liabilities	$ —	$(29,241,588)	$ —	$(29,241,588)
Total	$ —	$(29,241,588)	$ —	$(29,241,588)
As of December 31, 2022				
Commodity Derivatives - Assets				

Commodity Derivatives - Assets	Commodity Derivatives - Assets	$ —	$ 10,798,572	$ —	$ 10,798,572
Commodity Derivatives - Liabilities	Commodity Derivatives - Liabilities	$ —	$(23,831,269)	$ —	$(23,831,269)
Total	Total	$ —	$(13,032,697)	$ —	$(13,032,697)

Total

Total

As of December 31, 2023

As of December 31, 2023

As of December 31, 2023

Commodity Derivatives - Assets

Commodity Derivatives - Assets

Commodity Derivatives - Assets

Commodity Derivatives - Liabilities

Total

Total

Total

The carrying amounts reported for the revolving line of credit approximates fair value because the underlying instruments are at interest rates which approximate current market rates. The carrying amounts of receivables and accounts payable and other current assets and liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities.

NOTE 10 – 9 — REVOLVING LINE OF CREDIT

On July 1, 2014, the Company entered into a Credit Agreement with SunTrust Bank (now Truist), as lender, issuing bank and administrative agent for several banks and other financial institutions and lenders (the “Administrative Agent”), (which was amended several times) that provided for a maximum borrowing base of $1 billion with security consisting of substantially all of the assets of the Company. In April 2019, the Company amended and restated the Credit Agreement with the Administrative Agent (as amended and restated, the “Credit Facility”).

On August 31, 2022, the Company modified its Credit Facility through a Second Amended and Restated Credit Agreement (the "Second Credit Agreement"), extending the maturity date of the facility to August 2026. 2026 and the syndicate was modified to add five lenders, replacing five lenders. In conjunction with the Stronghold Acquisition, with the newly acquired assets put up for collateral, the Company established a borrowing base of $600 million. The borrowing base is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The borrowing base is redetermined semi-annually on each May 1 and November 1. November. The borrowing base is subject to reduction in certain circumstances such as the sale or disposition of certain oil and gas properties of the Company or its subsidiaries and cancellation of certain hedging positions.

The syndicate was modified to add five lenders, replacing five exiting lenders. Rather than Eurodollar loans, the reference rate on the Second Amended and Restated Credit Agreement is the Standard Overnight Financing Rate (“SOFR”). Beginning on the June 30, 2023 financial statements and compliance certification delivery date, SOFR. Also, the Second Amended and Restated Credit Agreement will allow for permits the Company to declare dividends for its equity owners, subject to certain limitations. These limitations, include including (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio as defined in (outstanding debt to adjusted earnings before interest, taxes, depreciation and amortization, exploration expenses, and all other non-cash charges acceptable to the Second Amended and Restated Credit Agreement, Administrative Agent) does not exceed 2.00 to 1.00, (iii) the amount of such payments does not exceed Available Free Cash Flow (as defined in the Second Credit Agreement), and (iv) the Borrowing Base Utilization Percentage (as defined in the Second Credit Agreement) is not greater than 80%, and (v) a Responsible Officer certifies that the other four conditions are satisfied. .

The interest rate on each SOFR Loan will be the adjusted term SOFR for the applicable interest period plus a margin between 3.0% and 4.0% (depending on the then-current level of borrowing base usage). The annual interest rate on each base rate Loan is (a) the greatest of (i) the Administrative Agent’s prime lending rate, (ii) the Federal Funds Rate (as defined in the Second Amended and Restated Credit Agreement) plus 0.5% per annum, (iii) the adjusted term SOFR determined on a daily basis for an interest period of one month, plus 1.00% per annum and (iv) 0.00% per annum, plus (b) a margin between 2.0% and 3.0% per annum (depending on the then-current level of borrowing base usage).

The Second Amended and Restated Credit Agreement contains certain covenants, which, among other things, require the maintenance of (i) a total Leverage Ratio (outstanding debt to adjusted earnings before interest, taxes, depreciation and amortization, exploration expenses, and all other non-cash charges acceptable to the Administrative Agent) of not more than 3.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Second Amended and Restated Credit Agreement) of 1.0 to 1.0.

The Second Credit Agreement also contains other customary affirmative and negative covenants and events of default. The Company is required to maintain on a rolling 24 months basis, hedging transactions in respect of crude oil and natural gas, on not less than 50% of the projected production from its proved, developed, producing oil and gas. If However, if the borrowing base utilization is less than 25% at the hedge testing date and the leverage ratio Leverage Ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall will be 0% from such hedge testing date to the next succeeding hedge testing date. If date and if the borrowing base utilization percentage is equal to or greater than 25%, but less than 50% and the leverage ratio Leverage Ratio is not greater than 1.25 to 1.00, the required hedging percentage for months 13 through 24 of the rolling 24 month period provided for shall will be 25% from such hedge testing date to the next succeeding hedge testing date.

The Second Amended and Restated Credit Agreement also contains other customary affirmative and negative covenants and events of default. As of December 31, 2022 December 31, 2023, $415,000,000 $425 million was outstanding on the Credit Facility. The Facility and the Company is was in compliance with all covenants contained in the Second Amended and Restated Credit Agreement as of December 31, 2022. Agreement.

Under the Second Amended and Restated Credit Agreement, the applicable percentage for the unused commitment fee is 0.5% per annum for all levels of borrowing base utilization. As of December 31, 2022 December 31, 2023, the Company's unused line of credit was $184,239,562, representative of a borrowing base of $600 $174.2 million, less which was calculated by subtracting the outstanding Credit Facility balance of $415 million, $425 million and standby letters of credit of $760,438 in total ($260,000 with state and federal agencies and $500,438 with an insurance company for New Mexico surety bonds). from the $600 million borrowing base. Note 15 - 14 — COMMITMENTS AND CONTINGENT LIABILITIES CONTINGENCIES describes changes in the surety bonds which did not yet affect the letters of credit (collateral) aforementioned.

NOTE 11 – 10 — ASSET RETIREMENT OBLIGATION

A reconciliation of the asset retirement obligation for the years ended December 31, 2022 December 31, 2023, 2021 2022 and 2020 2021 is as follows:

Balance, December 31, 2019	$	16,787,219
Liabilities incurred		99,436
Liabilities settled		(710,577)
Revision of estimate (1)		34,441
Accretion expense		906,616
Balance, December 31, 2020	$	17,117,135
Liabilities acquired		662,705
Liabilities incurred		171,390
Liabilities sold		(2,934,126)
Liabilities settled		(904,514)
Revision of estimate (1)		435,419
Accretion expense		744,045
Balance, December 31, 2021	$	15,292,054
Liabilities acquired		14,538,550
Liabilities incurred		353,008
Liabilities sold		—
Liabilities settled		(940,738)
Revision of estimate (1)		—
Accretion expense		983,432
Balance, December 31, 2022	$	30,226,306
Liabilities acquired		2,090,777
Liabilities incurred		439,528
Liabilities sold		(5,340,211)
Liabilities settled		(647,828)
Revision of estimate (1)		53,826
Accretion expense		1,425,686
Balance, December 31, 2023	$	28,248,084

(1) Several factors are considered in the annual review process, including current estimates for removal cost and estimated remaining useful life of the assets. The 2020 revision of estimates reflect an adjustment to the estimates for plugging costs. The 2021 revision of estimates primarily reflect updated interests for our working interest partners.

The following table presents the Company's current and non-current asset retirement obligation balances as of the periods specified.

	December 31, 2023	December 31, 2022
Asset retirement obligations, current	$ 165,642	$ 635,843
Asset retirement obligations, non-current	28,082,442	29,590,463
Asset retirement obligations	$ 28,248,084	$ 30,226,306

NOTE 12 – STOCKHOLDERS' 11 — STOCKHOLDERS' EQUITY

The Company is was authorized to issue 225,000,000 shares of common stock, with a par value of $0.001 per share, and 50,000,000 shares of preferred stock with a par value per share of $0.001 per share. On May 25, 2023, at the Company's annual meeting of stockholders, the Company's stockholders approved an amendment (the "Charter Amendment") to the Articles of Incorporation of the Company to increase the authorized shares of common stock from 225,000,000 to 450,000,000.

Issuance of equity instruments in public and private offerings – In October 2020, the Company closed on an underwritten public offering of (i) 9,575,800 shares of common stock, (ii) 13,428,500 Pre-Funded Warrants and (iii) 23,004,300 warrants to purchase common stock (the "Common Warrants") at a combined purchase price of $0.70. This includes a

partial exercise of the over-allotment. The Common Warrants have a term of five years ending in October 2025 and an exercise price of $0.80 per share. Gross proceeds totaled $16,089,582.

Concurrently with the underwritten public offering, the Company closed on a registered direct offering of (i) 3,500,000 shares of common stock, (ii) 3,300,000 Pre-Funded Warrants and (iii) 6,800,000 Common Warrants at a combined purchase price of $0.70 per share of common stock and Pre-Funded Warrants. The Common Warrants have a term of five years ending in October 2025 and an exercise price of $0.80 per share. Gross proceeds totaled $4,756,700.

Total gross proceeds from the 2020 underwritten public offering and the registered direct offering aggregated $20,846,282. Total net proceeds for the Common Warrants exercised in 2020 aggregated $19,379,832.

Common stock issued pursuant to warrant exercise - In December 2020, the Company issued 3,300,000 shares of common stock pursuant to the exercise of Pre-Funded Warrants issued in the October 2020 registered direct offering. Gross and net proceeds were $3,300. In January 2021, the remaining 13,428,500 Pre-Funded Warrants were exercised. During the year ended December 31, 2021, 442,600 of the Common Warrants were exercised. Accordingly, the number of Common Warrants outstanding as of December 31, 2021 was 29,361,700. During the year ended December 31, 2022, a total of 10,253,907 Common Warrants were exercised, leaving the 19,107,793 Common Warrants outstanding as of December 31, 2022 to be 19,107,793. .

During February and March 2023, a total of 4,517,427 Common stock returned from property acquisition – As part Warrants were exercised, at the exercise price of $0.80 per share. On April 11 and 12, 2023, the Company and certain holders of the Wishbone asset acquisition in April 2019, common warrants (the "Participating Holders") entered into a form of Warrant Amendment and Exercise Agreement (the "Exercise Agreement") pursuant to which the Company issued 4,576,951 shares agreed to reduce the exercise price of an aggregate of 14,512,166 common stock. In April 2020, 16,702 shares of common stock were returned and cancelled as settlement of post-closing adjustments. The shares were valued at February 25, 2019, warrants held by such Participating Holders from $0.80 to $0.62 per share (the "Reduced Exercise Price") in consideration for the date immediate exercise of the signing common warrants held by such Participating Holders in full at the Reduced Exercise Price in cash. The Company received aggregate gross proceeds of $8,997,543 from the exercise of the Purchase and Sale Agreement. The price on February 25, 2019 common warrants by the Participating Holders pursuant to the Exercise Agreement, which was $6.19 per share. The aggregate value recognized as an equity issuance cost in accordance with ASC 815-40-35-17(a). In the Statements of Stockholders' Equity, the shares returned, based on this price, was $103,385.net impact to Stockholders' Equity is $8,687,655, which is net of $309,888 in advisory fees. As of December 31, 2023, a total of 78,200 Common Warrants remained outstanding.

Common stock issued for Stronghold acquisition - As part of the Stronghold Acquisition, 21,339,986 shares of common stock were issued to the sellers. Also as part of the Stronghold Acquisition, 153,176 shares of Preferred Stock were issued to the sellers. Each share of Preferred Stock was automatically convertible into 277.7778 shares of common stock upon stockholder approval of the conversion. On October 27, 2022, the Company's stockholders approved the issuance of, 42,548,892 shares of common stock upon conversion of the 153,176 shares of our Preferred Stock. The preferred shares were automatically converted into such common shares as of October 27, 2022. Refer to "Note 5 - — ACQUISITIONS & DIVESTITURES" for the purchase price consideration allocated to the aforementioned stock issuances.

Common stock issued for option exercises – During the year years ended December 31, 2022 and 2021, the Company issued a net of 52,494 and 100,000 shares of common stock as a result of stock option exercises, respectively. No stock options were exercised in 2020. 2023. The following tables present the details of the exercises:

	Options exercised	Exercise price ($)	Shares issued	Shares retained	Cash paid at exercise ($)	Stock price on date of exercise ($)	Aggregate value of shares retained ($)
2021	100,000	$ 2.00	100,000	—	$ 200,000	$ 3.14	$ —
2021 Totals	100,000		100,000	—	$ 200,000		—
2021 Weighted Averages		$ 2.00				$ 3.14	

	Options exercised	Exercise price ($)	Shares issued	Shares retained	Cash paid at exercise ($)	Stock price on date of exercise ($)	Aggregate value of shares retained ($)
2022	100,000	$ 2.00	52,494	47,506	$ —	$ 4.21	$ 200,000
2022 Totals	100,000		52,494	47,506	$ —		200,000
2022 Weighted Averages		$ 2.00				$ 4.21	

NOTE 13 – 12 — EMPLOYEE STOCK OPTIONS, RESTRICTED STOCK AWARD PLAN, AND 401(k)

In June 2020, officers and directors of the Company voluntarily returned stock options that had previously been granted to them. In total, 2,265,000 options with a weighted average exercise price of $6.87 per share were returned to and cancelled by the Company. No grants, cash payments or other consideration has been or will be made to replace the options or otherwise in connection with the return. As a result of the return and cancellation of the options, the Company incurred additional compensation expense of $768,379.

During October and December 2020, as a result of changes to the executive team and the Board of Directors (the "Board") of the Company, the Company accelerated the vesting of 1,131,955 shares of restricted stock and as a result of such acceleration, the Company incurred additional compensation expense of $2,361,362. 401(K)

Compensation expense charged against income for share-based awards during the years ended December 31, 2022 December 31, 2023, 2022, and 2021 was $8,833,425, $7,162,231, and 2020 was $7,162,231, $2,418,323, and $5,364,162, respectively. These amounts are included in general General and administrative expense in the Statements of Operations.

In 2011, the Board approved and adopted a long-term incentive plan (the "2011 Plan"), which was subsequently approved and amended by the shareholders. There were 341,755 536,755 shares eligible for grant, either as stock options or as restricted stock, as of December 31, 2022 December 31, 2023.

In 2021, the Board approved and adopted the Ring Energy, Inc. 2021 Omnibus Incentive Plan (the "2021 Plan"), which was subsequently approved and amended by the shareholders at the 2021 Annual Meeting. There The 2021 Plan provides that the Company may grant options, stock appreciation rights, restricted shares, restricted stock units, performance-based awards, other share-based awards, other cash-based awards, or any combination of the foregoing. At the 2023 Annual Meeting, the shareholders approved an amendment to the 2021 Plan to increase the number of shares available under the 2021 Plan by 6.0 million. Accordingly, there were 5,591,224 8,224,394 shares eligible available for grant either as stock options or as restricted stock, as of December 31, 2022. December 31, 2023 under the 2021 Plan.

Employee Stock Options – No stock options have been were granted in the years ended December 31, 2022 December 31, 2023, 2021, 2022, or 2020. 2021. All outstanding stock option awards vest at the rate of 20% each year over five years beginning one year from the date granted

and expire ten years from the grant date. A summary of the status of the stock options as of December 31, 2022 December 31, 2023, 2021, 2022, and 2020 2021 and changes during the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020 2021 is as follows:

	2022		2021		2020	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
	2023		**2022**		**2021**	
	Options	**Weighted-Average Exercise Price**	**Options**	**Weighted-Average Exercise Price**	**Options**	**Weighted-Average Exercise Price**
Outstanding at beginning of year Outstanding at beginning of year	365,500	$ 3.61	465,500	$ 3.26	2,748,500	$ 6.28
Issued	—	—	—	—	—	—
Forfeited or rescinded	—	—	—	—	(2,283,000)	6.89

Granted							
Forfeited							
Expired							
Exercised	Exercised	(100,000)	2.00	(100,000)	2.00	—	—
Outstanding at end of year	Outstanding at end of year	265,500	$ 4.21	365,500	$ 3.61	465,500	$ 3.26
Outstanding at end of year							
Outstanding at end of year							
Exercisable at end of year	Exercisable at end of year	265,500	$ 4.21	365,500	$ 3.61	455,300	$ 3.11
Exercisable at end of year							
Exercisable at end of year							

For the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020 2021, the Company incurred share-based compensation expense related to stock options of $ —, $0, $0, and $20,934, and $927,559, respectively. As of December 31, 2022 December 31, 2023, the Company had $0 of unrecognized compensation cost related to stock options. The aggregate intrinsic value of options vested and expected to vest as of December 31, 2022 December 31, 2023 was $89,700. $0. The aggregate intrinsic value of options exercisable at December 31, 2022 December 31, 2023 was $89,700. $0. The year-end intrinsic values are based on a December 31, 2022 December 31, 2023 closing stock price of $2.46. $1.46.

No stock options were exercised during 2023. Stock options exercised of 100,000 shares in 2022 had an aggregate intrinsic value on the date of exercise of $221,000. Stock options exercised of 100,000 shares in 2021 had an aggregate intrinsic value on the date of exercise of $114,000. No stock options were exercised in 2020.

The following table summarizes information related to the Company's stock options outstanding as of December 31, 2022 December 31, 2023:

Options Outstanding									
Exercise price									
Exercise price									
Exercise price							Number Outstanding	Weighted-Average Remaining Contractual Life (in years)	Number Exercisable
	Options Outstanding								
	Exercise price	Number Outstanding	Weighted-Average Remaining Contractual Life (in years)	Number Exercisable					
$	2.00	195,000	1.00	195,000					
	5.50								
	5.50								
5.50	5.50	5,000	1.21	5,000		5,000	5,000	0.21	5,000
14.54	14.54	10,000	2.74	10,000	14.54	10,000	10,000	1.74	10,000
8.00	8.00	4,500	2.92	4,500	8.00	4,500	4,500	1.92	4,500
6.42	6.42	15,000	3.34	15,000	6.42	15,000	15,000	2.34	15,000
11.75	11.75	36,000	3.95	36,000	11.75	36,000	36,000	2.95	36,000
		265,500	1.63	265,500					
$					10.33		70,500	2.39	70,500

Restricted stock unit grants – Following is a table reflecting the restricted stock unit grants during 2023, 2022 2021 and 2020: 2021:

Grant date	# of shares of restricted stock
October 1, 2020	900,000
October 26, 2020	150,000
December 15, 2020	930,000 units
April 30, 2021	33,950
June 17, 2021	1,162,152
July 6, 2021	11,824
July 12, 2021	4,007
September 1, 2021	10,417
September 8, 2021	3,306
February 9, 2022	1,247,061
April 13, 2022	7,143
May 10, 2022	10,349
June 16, 2022	2,150
July 14, 2022	8,547
August 29, 2022	30,581
September 1, 2022	37,797
September 19, 2022	49,645
February 16, 2023	2,270,842

Restricted stock unit grants issued prior to 2020 vest at the rate of 20% each year over five years beginning one year from the date granted. Restricted stock unit grants issued during 2020 and in following years vest at a rate of 33% each year over three years beginning one year from the date granted for all employees; for members of the Board, the 2021 restricted stock unit grants vest on the earliest of (i) the day before the next shareholder meeting or (ii) the first anniversary of the date of the award. award for 2022 restricted stock units. Forfeitures are recognized as a reduction to share-based compensation expense in the period of occurrence. A summary of the status of restricted stock unit grants and changes during the years ended December 31, 2022 December 31, 2023, 2021 2022 and 2020 2021 is as follows:

		2022		2021		2020	
		Restricted stock	Weighted-Average Grant Date Fair Value	Restricted stock	Weighted-Average Grant Date Fair Value	Restricted stock	Weighted-Average Grant Date Fair Value
		2023		2022		2021	
		Restricted stock units	Weighted-Average Grant Date Fair Value	Restricted stock units	Weighted-Average Grant Date Fair Value	Restricted stock units	Weighted-Average Grant Date Fair Value
Outstanding at beginning of year	Outstanding at beginning of year	2,572,596	$ 1.75	2,132,297	$ 2.94	1,341,889	$ 4.99
Granted	Granted	1,393,273	2.83	1,225,656	2.77	1,980,000	0.71
Forfeited or rescinded	Forfeited or rescinded	(31,185)	2.83	0	—	(9,200)	3.97
Vested	Vested	(1,310,894)	1.79	(785,357)	1.37	(1,180,392)	4.97
Outstanding at end of year	Outstanding at end of year	2,623,790	$ 2.29	2,572,596	$ 1.75	2,132,297	$ 2.94

For the years ended December 31, 2022 December 31, 2023, 2021 2022 and 2020, 2021, the Company incurred share-based compensation expense related to restricted stock unit grants of $4,537,026, $4,148,639, $2,225,895, and $4,436,603, $2,225,895, respectively. As of December 31, 2022 December 31, 2023, the Company had $2,457,386 $2,778,549 of unrecognized compensation cost related to restricted stock unit grants that will be recognized over a weighted average period of 1.78 1.72 years.

During 2023, 2022, and 2021, 1,680,232, 1,310,894, and 2020, 1,310,894, 785,357 and 1,180,392 shares of restricted stock units vested, respectively. At the dates of vesting those shares restricted stock units had an aggregate intrinsic value of $3,203,568, $3,807,996, $2,049,603, and $801,133, $2,049,603, respectively.

Performance Stock Units - In accordance with the 2021 Plan, as of November 22, 2021, the Company entered into performance stock unit ("PSU") agreements (the "PSU Agreement") with certain employees. Upon approval the Board, a total of 860,216 PSU were granted to the Company's five executive officers (the "2021 PSU Awards"). The performance

period for the 2021 PSU Awards began on January 1, 2021, and will end December 31, 2023, with such awards vesting on the last day of the performance period (the vesting date). The PSUs are performance-based restricted stock units subject to the terms of the 2021 Plan and the PSU Agreement. Upon Board approval, a total of

860,216 PSUs were granted to the Company's five executive officers (the "2021 PSU Awards"). The performance period for the 2021 PSU Awards began on January 1, 2021, and ended on December 31, 2023. Based on the achievement of the performance goals for the 2021 PSU Awards, a total of 1,170,024 PSUs vested on December 31, 2023. On February 9, 2022, the Company granted additional PSU awards. A a total of 860,216 PSU awards were granted PSUs to the Company's five executive officers (the "2022 PSU Awards"). The performance period for the 2022 PSU Awards began on January 1, 2022, and will end on December 31, 2024, with such awards vesting on the last day of the performance period (the vesting date). The PSUs are performance-based restricted stock units subject to the terms of the 2021 Plan and the PSU Agreement. On February 16, 2023, the Company granted a total of 1,162,162 PSUs to the Company's five executive officers (the "2023 PSU Awards"). The performance period for the 2023 PSU Awards began on January 1, 2023, and will end on December 31, 2025.

A summary of the status of the performance stock grants as of December 31, 2022 PSU awards and 2021 along with changes during the year years ended December 31, 2022 December 31, 2023, 2022 and 2021 are as follows:

		2022		2021		2023		2022		2021	
		Performance Stock Units	Weighted-Average Grant Date Fair Value	Performance Stock Units	Weighted-Average Grant Date Fair Value	Performance Stock Units	Weighted-Average Grant Date Fair Value	Performance Stock Units	Weighted-Average Grant Date Fair Value	Performance Stock Units	Weighted-Average Grant Date Fair Value
		2023 Performance Stock Units									
Outstanding at beginning of year	Outstanding at beginning of year	860,216	$ 3.87	—	$ —						
Granted	Granted	860,216	3.65	860,216	3.87						
Incremental performance stock units vested											
Forfeited or rescinded	Forfeited or rescinded	—	—	—	—						
Vested	Vested	—	—	—	—						
Outstanding at end of year	Outstanding at end of year	1,720,432	$ 3.76	860,216	$ 3.87						

No forfeitures for the PSU awards have been recognized as of December 31, 2023, but the Company would recognize any such forfeitures in the period of occurrence as a reduction to share-based compensation expense. For the year years ended December 31, 2022 December 31, 2023, 2022 and 2021, the Company incurred share-based compensation expense related to the PSU Awards of $4,296,399, $3,013,592, and $171,494, respectively. As of December 31, 2022 December 31, 2023, the Company had $4,037,141 $4,015,133 of unrecognized compensation cost related to the PSU Awards that will be recognized over a weighted average period of 1.56 1.57 years.

During 2023, 1,170,024 PSUs vested. At the dates of vesting those PSUs had an aggregate intrinsic value of $1,708,235.

401(k) Plan- In 2019, the Company initiated a sponsored 401(k) plan that is a defined contribution plan for the benefit of all eligible employees. The plan allows eligible employees, after a three-month waiting period, to make pre-tax or after-tax contributions, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of any employee's compensation. Employees are 100% vested in the employer contribution upon receipt.

The following table presents the matching contributions expense recognized for the Company's 401(k) plan for the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020: 2021:

	2022	2021	2020
Employer safe harbor match	284,094	228,273	138,997

	2023	2022	2021
Employer safe harbor match	$ 346,268	$ 284,094	$ 228,273

NOTE 14 – 13 — RELATED PARTY TRANSACTIONS

The Company leased office space in Tulsa, Oklahoma, from Arenaco, LLC ("Arenaco"), a company that is was owned by two stockholders of the Company, Mr. Rochford, former Chairman of the Board, and Mr. McCabe, a former director of the Company. During the years year ended December 31, 2021 and 2020, , the Company paid $10,000 and $60,000 respectively, to Arenaco. The month-to-month Arenaco lease was terminated as of March 31, 2021.

During June 2021, the Company began using Pro-Ject Chemicals, LLC ("PJ Chemicals") to perform various chemical services on its wells. As publicly disclosed on the Company's website, Paul D. McKinney, Chief Executive Officer and Chairman of the Board, was a member of the board of directors of Pro-Ject Holdings, LLC, a privately owned oil field chemical services company and parent of PJ Chemicals. Mr. McKinney owned 0.34% of the shares of Pro-Ject Holdings, LLC. During the year ended December 31, 2021, the Company paid $117,830 to PJ Chemicals. As of December 31, 2021 the Company had accounts payable of $37,641 due to PJ Chemicals. As of 2022, Mr. McKinney is was no longer on the board of directors of Pro-Ject Holdings, LLC.

NOTE 15 – 14 — COMMITMENTS AND CONTINGENT LIABILITIES CONTINGENCIES

Standby Letters of Credit – A commercial bank issued standby letters of credit on behalf of the Company totaling $260,000 to state and federal agencies and $500,438 to an insurance company to secure the surety bonds described below. The standby letters of credit are valid until cancelled or matured and are collateralized by the revolving credit facility with the bank. The terms of the letters of credit to the state and federal agencies are extended for a term of one year at a time. The Company intends to renew the standby letters of credit to the state and federal agencies for as long as the Company does business in the States State of Texas and New Mexico. Texas. The letters of credit to the insurance company will be renewed if the insurance requires them to retain the surety bonds. bonds; however, as the Company no longer operates any wells in the State of New Mexico, these standby letters of credit will not be renewed. No amounts have been drawn under the standby letters of credit.

Surety Bonds – An insurance company issued surety bonds on behalf of the Company totaling $500,438 to various State of New Mexico agencies in order for the Company to do business in the State of New Mexico. The surety bonds are valid until canceled or matured. The terms of the surety bonds are extended for a term of one year at a time. The Company intends does not intend to renew the surety bonds on $400,000 as long as the Company does business in the State of New Mexico. The remaining $100,438 is related Mexico, as these operated assets have now been sold to inactive wells and will remain in place until the Company returns those wells to activity or plugs them. One of those wells has been plugged, and the bond released in the amount of $50,150, leaving the amount related to inactive wells as $50,288. On December 23, 2022, the Company increased its blanket plugging surety bond by $200,000. a third party. As of December 31, 2022 December 31, 2023, the Company had remaining surety bonds in total of $650,288. $25,000.

NOTE 16 – 15 — INCOME TAXES

For the years ended December 31, 2022 December 31, 2023, 2021, 2022, and 2020, 2021, components of our provision for (benefit from) income taxes are as follows:

Provision for Income Taxes:	Provision for Income Taxes:	2023	2022	2021

Federal deferred tax

State current tax

State deferred tax

Provision for Income Taxes	**Provision for Income Taxes**	**2022**	**2021**	**2020**
Federal deferred tax		$6,437,680	$ —	$(6,001,176)
State deferred tax		1,971,044	90,342	—
Provision for (Benefit From) Income Taxes		$8,408,724	$90,342	$(6,001,176)

The following is a reconciliation of income taxes computed using the U.S. federal statutory rate to the provision for (benefit from) income taxes:

Rate Reconciliation		**2022**	**2021**	**2020**
Pre-tax book income (loss)		$147,043,749	$3,413,234	$(259,413,004)
Rate Reconciliation:	**Rate Reconciliation:**	**2023**	**2022**	**2021**
Pre-tax book income (1)				
Tax at federal statutory rate	Tax at federal statutory rate	$ 30,879,187	$ 716,779	$ (54,476,731)
Excess tax benefit from stock option exercises and restricted stock vesting	Excess tax benefit from stock option exercises and restricted stock vesting	(312,268)	(175,187)	(1,109,379)
Adjust prior estimates to tax return	Adjust prior estimates to tax return	214,740	2,938,948	(1,930,994)
States taxes, net of federal benefit	States taxes, net of federal benefit	1,443,145	430,654	(964,393)
Valuation allowance	Valuation allowance	(24,151,242)	(3,827,194)	52,161,412
Non-deductible expenses and other	Non-deductible expenses and other	335,162	6,342	318,909

Provision for (Benefit From) Income Taxes	$ 8,408,724	$ 90,342	$ (6,001,176)
Provision for Income Taxes			

(1) Amount represents pre-tax book income, net of income taxes paid.

The Company's deferred tax position reflects the net tax effects of the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. The net deferred taxes consisted of the following as of December 31, 2022 December 31, 2023 and 2021: 2022:

		12/31/2022 Total	12/31/2021 Total
	12/31/2023 Total	12/31/2023 Total	12/31/2022 Total
Deferred Tax Assets	**Deferred Tax Assets**		
Net operating loss (NOL) carryforward			
Net operating loss (NOL) carryforward			
Net operating loss (NOL) carryforward	Net operating loss (NOL) carryforward	70,564,004	60,155,112
Equity compensation	Equity compensation	1,554,680	691,076
Asset retirement obligation	Asset retirement obligation	6,635,099	3,348,875
Fair market value of derivatives	Fair market value of derivatives	2,827,202	6,403,745
§163(j) business interest expense carryforward	§163(j) business interest expense carryforward	4,917,358	—
Others	Others	1,173,441	61,077
Gross Deferred Tax Assets	**Gross Deferred Tax Assets**	87,671,784	70,659,885
Less: valuation allowance	Less: valuation allowance	(24,182,975)	(48,334,217)
Net Deferred Tax Assets	**Net Deferred Tax Assets**	63,488,809	22,325,668
Deferred Tax Liabilities	**Deferred Tax Liabilities**		
Deferred Tax Liabilities			
Deferred Tax Liabilities			
Property and equipment			
Property and equipment			

Property and equipment	Property and equipment	(71,402,820)	(22,415,959)
Other	Other	(585,005)	—
Net Deferred Liabilities	**Net Deferred Liabilities**	(71,987,825)	(22,415,959)
Net Deferred Tax Liabilities	**Net Deferred Tax Liabilities**	(8,499,016)	(90,292)
Net Deferred Tax Liabilities			
Net Deferred Tax Liabilities			

As of December 31, 2022 December 31, 2023, the Company had net operating loss carryforwards for federal income tax reporting purposes of approximately $109.3 million which, if unused, will begin to expire in 2027 and fully expire in 2037 and an additional $225.1 million $279.2 million that can be carried forward indefinitely. The shares issued for the Stronghold Acquisition (further discussed in Note 5 - "ACQUISITIONS — ACQUISITIONS & DIVESTITURES) resulted in the Company having an ownership change under Section 382 of the Internal Revenue Code of 1986, as amended. Section 382 limits the availability of certain tax attributes, including net operating losses and disallowed interest carryforwards, to offset future taxable income of the Company. In evaluating its need for a valuation allowance against its deferred tax assets, the Company has estimated the amount of tax attributes related to the pre-ownership change period to be available under Section 382 in periods in which it expects deferred tax liabilities to be realized based on currently available information. Based on its current analysis, the Company does not anticipate any material tax attributes to expire unused as result of the Section 382 ownership change; however, the ultimate timing in the amount of tax attributes available in future periods may be different than the Company's current estimate and will be determined in each year as new information becomes available. Changes in expectation in the timing of the availability of the Company's tax attributes could result in adjustments to the valuation allowance in future years as it updates its analysis based on new information.

As of December 31, 2022 December 31, 2023, we carried a valuation allowance against our federal and state deferred tax assets of $24,182,975. $0. We have considered both the positive and negative evidence in determining whether it was more likely than not that some portion or all of our deferred tax assets will be realized. The amount of deferred tax assets considered realizable could, however, be adjusted if estimates of future taxable income during the carryforward period are reduced or increased or if objective negative evidence is no longer present and additional weight is given to subjective positive evidence, including projections for growth. During 2022, As of June 30, 2023, the Company determined that certain existing was no longer in a cumulative loss position. As a result, future forecasted pre-tax book income was considered as positive evidence in assessing the valuation allowance. Based on the change in judgment on the realizability of the related federal deferred tax assets will not be offset by existing deferred tax liabilities in future years, the Company released $24.2 million of valuation allowance as a result of benefit during the 80% limitation on the utilization of net operating losses incurred after 2017. year ended December 31, 2023. This results resulted in an ending federal net deferred tax liability after valuation allowance of $6,437,680. $5,536,158. Additionally, the Company reported a net state deferred tax liability at December 31, 2022 December 31, 2023 of $2,061,336 $3,015,887 attributable to certain state deferred tax liabilities mainly associated with property and equipment.

NOTE 17 – 16 — LEGAL MATTERS

The Company is a defendant in a lawsuit in Harris County District Court, Houston, Texas, styled EPUS Permian Assets, LLC, v. Ring Energy, Inc., that was filed in July 2021. The plaintiff, EPUS Permian Assets, LLC, claims breach of contract, money had and received by fraudulent inducement, unjust enrichment and constructive trust. The plaintiff is requesting its forfeited deposit of $5,500,000 in connection with a proposed property sale by the Company plus related damages, and attorneys' fees and costs. The action relates to a proposed property sale by the Company to the plaintiff, which was extended by the Company on several occasions with the plaintiff ultimately failing to perform on the agreement and the Company keeping the deposit. The Company believes that the claims by the plaintiff are entirely without merit and is conducting a vigorous defense and counterclaim. The Company has filed an answer and a counterclaim denying the allegations and asserting affirmative defenses that would bar or substantially limit the plaintiff's claims, asserting breach of contract and requesting a declaratory judgment and attorneys' fees and costs. The parties have taken begun taking depositions and are conducting discovery.

NOTE 18 – 17 — SUBSEQUENT EVENTS

Stronghold acquisition Surety Bonds -On January 10, 2024, two insurance companies issued surety bonds on behalf of the Company, one for $250,000, an RRC required blanket performance bond to operate 100 wells or more in the State of Texas, and one for $2,000,000, an RRC required blanket plugging extension bond, each with zero collateral requirements. The term for these two surety bonds ends on July 1, 2025 and can be renewed at that time.

First Amendment to Second Amended and Restated Credit Agreement **-** On February 28, 2023, as discussed in "Note 5 - ACQUISITIONS & DIVESTITURES," the deferred cash consideration of $15.0 million in cash was paid to Stronghold in accordance with terms set forth in the Purchase Agreement for the Stronghold Acquisition. In addition on March 1, 2023, the holdback amount of approximately $8.3 million which was held in escrow in accordance with the terms set forth in the Purchase Agreement for the Stronghold Acquisition was distributed to Stronghold.

Common stock issued pursuant to warrant exercise - On February 2, 2023 February 12, 2024, the Company, issued 2,517,427 shares of common stock pursuant Truist Bank ("Truist") as the Administrative Agent and Issuing Bank, and the lenders party thereto (the "Lenders") entered into an amendment (the "Amendment") to the exercise of Common Warrants with an exercise price of $0.80. Gross Second Amended and net proceeds were $2,013,942. On March 1, 2023 Restated Credit Agreement dated August 31, 2022, by and among the Company, issued 2,000,000 shares as Borrower, Truist as Administrative Agent and Issuing Bank, and the Lenders (together with all amendments or other modifications, the "Credit Agreement"). Among other things, the Amendment amends the definition of common stock pursuant to Free Cash Flow so amounts used by the exercise Company for acquisitions will no longer be subtracted from the calculation of Common Warrants with an exercise price of $0.80. Gross and net proceeds were $1,600,000. Free Cash Flow.

RING ENERGY, INC.
SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES
(Unaudited)

Results of Operations from Oil and Natural Gas Producing Activities – The Company's results of operations from oil and natural gas producing activities exclude interest expense, gain from change in fair value of derivatives, and other financing expense.

For the years ended December 31,	*For the years ended December 31,*	2022	2021	2020	*For the years ended December 31,*	2023	2022	2021
Oil, natural gas, and natural gas liquids sales	Oil, natural gas, and natural gas liquids sales	$ 347,249,537	$ 196,305,966	$ 113,025,138				
Lease operating expenses	Lease operating expenses	(47,695,351)	(30,312,399)	(29,753,413)				
Gathering, transportation and processing costs	Gathering, transportation and processing costs	(1,830,024)	(4,333,232)	(4,090,238)				
Ad valorem taxes	Ad valorem taxes	(4,670,617)	(2,276,463)	(3,125,222)				
Production taxes	Production taxes	(17,125,982)	(9,123,420)	(5,228,090)				
Depreciation, depletion, and amortization	Depreciation, depletion, and amortization	(55,740,767)	(37,167,967)	(43,010,660)				
Ceiling test impairment		—	—	(277,501,943)				
General and administrative (exclusive of corporate overhead)	General and administrative (exclusive of corporate overhead)	(1,617,095)	(2,003,876)	(1,454,041)				
Results of Oil, Natural Gas, and Natural Gas Liquids Producing Operations		$ 218,569,701	$ 111,088,609	$ (251,138,469)				
General and administrative (exclusive of corporate overhead)								
General and administrative (exclusive of corporate overhead)								
Income tax expense								
Results of Oil and Natural Gas Producing Operations								

Net Costs Incurred in Oil and Gas Producing Activities

For the years Ended December 31,		2022		2021
Payments for the Stronghold Acquisition	$	177,823,787	$	—
Payments to purchase oil and natural gas properties		1,563,703		1,368,437
Payments to develop oil and natural gas properties		129,332,155		51,302,131
Payments to acquire or improve fixed assets subject to depreciation		319,945		568,832
Sale of fixed assets subject to depreciation		(134,600)		—
Proceeds from divestiture of oil and natural gas properties		(23,700)		(2,000,000)
Total Net Costs Incurred	$	308,881,290	$	51,239,400

For the years Ended December 31,		2023		2022		2021
Payments to acquire oil and natural gas properties	$	82,900,900	$	179,387,490	$	1,368,437
Payments to explore oil and natural gas properties		—		—		—
Payments to develop oil and natural gas properties		152,559,314		129,332,155		51,302,131
Total costs incurred	$	235,460,214	$	308,719,645	$	52,670,568

Net Capitalized Costs

As of December 31,		2022		2021
Oil and natural gas properties, full cost method	$	1,463,838,595	$	883,844,745
Financing lease asset subject to depreciation		3,019,476		1,422,487
Fixed assets subject to depreciation		3,147,125		2,089,722
Total Properties and Equipment		1,470,005,196		887,356,954
Accumulated depletion, depreciation and amortization		(289,935,259)		(235,997,307)
Net Properties and Equipment	$	1,180,069,937	$	651,359,647

As of December 31,		2023		2022
Oil and natural gas properties, full cost method				
Proved properties		1,663,548,249		1,463,838,595
Unproved properties		—		—
Total oil and natural gas properties, full cost method		1,663,548,249		1,463,838,595
Accumulated depletion of oil and natural gas properties		(373,280,583)		(287,052,595)
Net oil and natural gas properties capitalized	$	1,290,267,666	$	1,176,786,000

Reserve Quantities Information – The following estimates of proved and proved developed reserve quantities and related standardized measure of discounted future net cash flow are estimates only, and do not purport to reflect realizable values or fair market values of the Company’s reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company’s reserves are located in the United States of America.

The proved reserves estimates shown herein for the years ended December 31, 2022 December 31, 2023, 2021 2022 and 2020 2021 have been prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

The reserve information in these Financial Statements represents only estimates. There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the Company’s control, such as commodity pricing. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. As a result, estimates by different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may lead to revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the Company's proved reserves will decline as reserves are produced.

The oil prices as of December 31, 2022 December 31, 2023, 2021 2022 and 2020 2021 are based on the respective 12-month unweighted average of the first of the month prices of the West Texas Intermediate ("WTI") WTI spot prices which equates to $74.70 per barrel, $90.15 per barrel $63.04 per barrel and $36.04 $63.04 per barrel, respectively. The natural gas prices as of December 31, 2022 December 31, 2023, 2021 2022 and 2020 2021 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $2.637 per MMBtu, $6.358 per MMBtu $3.598 per MMBtu and $1.99 $3.598 per MMBtu, respectively. Prices are adjusted by local field and lease level differentials and are held constant for life of reserves in accordance with SEC guidelines.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) NGLs) and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment and methods.

For the Year Ended December 31,	*For the Year Ended December 31,*	2022			*For the Year Ended December 31,*	2023			
		Oil (1)	**Natural Gas (1)**	**Natural Gas Liquids (1)**					
		Oil (1)				**Oil (1)**	**Natural Gas (1)**	**Natural Gas Liquids (1)**	**Boe**
Proved Developed and Undeveloped Reserves	**Proved Developed and Undeveloped Reserves**								
Beginning of year	Beginning of year	65,838,609	71,773,789	—					
Purchases of minerals in place		28,086,920	108,456,107	16,715,626					
Beginning of year									
Beginning of year						88,704,743	157,870,449	23,105,658	138,122,143
Purchase of minerals in place					Purchase of minerals in place	6,543,640	3,372,965	1,089,382	8,195,183
Extensions, discoveries and improved recovery	Extensions, discoveries and improved recovery	628,978	522,178	52,810	Extensions, discoveries and improved recovery	3,098,845	4,113,480	1,014,343	4,798,768
Sale of minerals in place		—	—	—					
Sales of minerals in place					Sales of minerals in place	(4,897,921)	(2,674,955)	(392,953)	(5,736,700)
Production	Production	(3,459,477)	(4,088,642)	(371,337)	Production	(4,579,942)	(6,339,158)	(976,852)	(6,613,320)
Revisions of previous quantity estimates	Revisions of previous quantity estimates	(2,390,287)	(18,792,983)	6,708,559	Revisions of previous quantity estimates	(6,728,088)	(9,946,459)	(621,014)	(9,006,845)
End of year	**End of year**	88,704,743	157,870,449	23,105,658					
End of year									
End of year						82,141,277	146,396,322	23,218,564	129,759,229
Proved Developed at beginning of year									
Proved Developed at beginning of year									
Proved Developed at beginning of year	**Proved Developed at beginning of year**	36,820,824	39,748,880	—		57,012,137	106,399,050	15,332,804	90,078,116

Proved Undeveloped at beginning of year	**Proved Undeveloped at beginning of year**	29,017,785	32,024,909	—	**Proved Undeveloped at beginning of year**	31,692,606	51,471,399	7,772,854	48,044,027
Proved Developed at end of year	**Proved Developed at end of year**	57,012,137	106,399,050	15,332,804					
Proved Developed at end of year									
Proved Developed at end of year						56,029,039	99,896,022	15,449,907	88,128,284
Proved Undeveloped at end of year	**Proved Undeveloped at end of year**	31,692,606	51,471,399	7,772,854	**Proved Undeveloped at end of year**	26,112,238	46,500,300	7,768,657	41,630,945

For the Year Ended December 31,	***For the Year Ended December 31,***	**2021**			***For the Year Ended December 31,***	**2022**			
		Oil (1)	**Natural Gas (1)**	**Natural Gas Liquids (1)**					
		Oil (1)				**Oil (1)**	**Natural Gas (1)**	**Natural Gas Liquids (1)**	**Boe**
Proved Developed and Undeveloped Reserves	**Proved Developed and Undeveloped Reserves**								
Beginning of year	Beginning of year	66,264,286	61,305,027	—					
Purchases of minerals in place		2,180,497	824,512	—					
Beginning of year									
Beginning of year						65,838,609	71,773,789	—	77,800,907
Purchase of minerals in place					Purchase of minerals in place	28,086,920	108,456,107	16,715,626	62,878,564
Extensions, discoveries and improved recovery	Extensions, discoveries and improved recovery	3,975,675	5,172,392	—	Extensions, discoveries and improved recovery	628,978	522,178	52,810	768,818
Sale of minerals in place		(462,970)	(555,879)	—					
Sales of minerals in place					Sales of minerals in place			—	
Production	Production	(2,686,940)	(2,535,188)	—	Production	(3,459,477)	(4,088,642)	(371,337)	(4,512,254)
Revisions of previous quantity estimates	Revisions of previous quantity estimates	(3,431,939)	7,562,925	—	Revisions of previous quantity estimates	(2,390,287)	(18,792,983)	6,708,559	1,186,108
End of year	**End of year**	65,838,609	71,773,789	—					
End of year									

End of year						88,704,743	157,870,449	23,105,658	138,122,143
Proved Developed at beginning of year									
Proved Developed at beginning of year									
Proved Developed at beginning of year	**Proved Developed at beginning of year**	38,260,638	34,335,520	—		36,820,824	39,748,880	—	43,445,637
Proved Undeveloped at beginning of year	**Proved Undeveloped at beginning of year**	28,003,648	26,969,507	—	**Proved Undeveloped at beginning of year**	29,017,785	32,024,909	—	34,355,270
Proved Developed at end of year	**Proved Developed at end of year**	36,820,824	39,748,880	—					
Proved Developed at end of year									
Proved Developed at end of year						57,012,137	106,399,050	15,332,804	90,078,116
Proved Undeveloped at end of year	**Proved Undeveloped at end of year**	29,017,785	32,024,909	—	**Proved Undeveloped at end of year**	31,692,606	51,471,399	7,772,854	48,044,027

1

(1) Oil reserves are stated in barrels; natural gas reserves are stated in thousand cubic feet; natural gas liquids NGL reserves are stated in barrels.

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During Notable changes in proved reserves for the year ended December 31, 2022, our December 31, 2023 included the following:

- *Extensions.* In 2023, extensions and discoveries of 769 MBoe (one thousand Boe) resulted 4.8 MMBoe were primarily from the 2022 result of the successful operated drilling program and non-operated activity in the Northwest Shelf and Central Basin Platform as well as non-operated activity Platform.
- *Purchase of minerals in place.* In 2023, the Northwest Shelf. Revisions Company completed the acquisition of 1,186 MBoe were predominately Founders oil and gas leases and related property within Ector County that resulted in 8.2 MMBoe in additional reserves.
- *Sales of minerals in place.* In 2023, the result Company sold 5.7 MMBoe from the divestiture of converting from two-stream the Delaware Basin assets (30%), the New Mexico operated assets (57%), and part of the Company's assets in Gaines County (13%).
- *Revision of previous estimates.* In 2023, the negative revisions of prior reserves of 9.0 MMBoe consisted of 5.3 MMBoe (59%) related to three-stream reserves, the removal of proved undeveloped reserves changes in our Delaware asset, well price and 3.7 MMBoe (41%) related to changes in performance increased cost from 2022 industry activity, and increased commodity pricing.

The increase in proved undeveloped reserves was primarily attributable to the Stronghold Acquisition. other economic factors.

Standardized Measure of Discounted Future Net Cash Flows – The standardized measure of discounted future net cash flows is computed by applying the price according to the SEC guidelines for oil and natural gas to the estimated future production of proved oil and natural gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax rates) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows.

Standardized Measure of Discounted Future Net Cash Flows

December 31,	***December 31,***	**2022**	**2021**	**2020**	***December 31,***	**2023**	**2022**	**2021**

Future cash inflows	Future cash inflows	$9,871,961,000	$4,853,709,000	$2,682,488,655
Future production costs	Future production costs	(2,751,896,250)	(1,395,437,250)	(821,515,126)
Future development costs		(647,196,750)	(347,757,000)	(244,323,270)
Future development costs (1)				
Future income taxes	Future income taxes	(1,142,147,641)	(501,586,949)	(208,645,934)
Future net cash flows	Future net cash flows	5,330,720,359	2,608,927,801	1,408,004,325
10% annual discount for estimated timing of cash flows	10% annual discount for estimated timing of cash flows	(3,058,606,841)	(1,471,562,953)	(852,133,072)
Standardized Measure of Discounted Future Net Cash Flows	**Standardized Measure of Discounted Future Net Cash Flows**	$2,272,113,518	$1,137,364,848	$ 555,871,253
Standardized Measure of Discounted Future Net Cash Flows				
Standardized Measure of Discounted Future Net Cash Flows				

(1) Future development costs include not only development costs but also future asset retirement costs.

The following is a summary of the changes in the Standardized Measure for the Company's proved oil and natural gas reserves during each of the years in the three-year period ended December 31, 2022 December 31, 2023:

Changes in Standardized Measure of Discounted Future Net Cash Flows

		2022	2021	2020
	2023	2023	2022	2021
Beginning of the year	Beginning of the year	$1,137,364,848	$ 555,871,253	$923,175,051
Purchase of minerals in place	Purchase of minerals in place	996,313,882	33,688,718	—
Extensions, discoveries and improved recovery	Extensions, discoveries and improved recovery	20,447,842	79,003,885	61,303,074
Development costs incurred during the year	Development costs incurred during the year	67,454,522	17,513,180	29,916,746

Sales of oil and gas produced, net of production costs	Sales of oil and gas produced, net of production costs	(283,588,498)	(154,615,685)	(70,634,853)
Sales of minerals in place	Sales of minerals in place	—	(2,523,746)	—
Accretion of discount	Accretion of discount	133,209,763	63,810,764	92,838,323
Net changes in price and production costs	Net changes in price and production costs	646,819,172	636,884,944	(368,974,767)
Net change in estimated future development costs	Net change in estimated future development costs	(53,253,626)	(44,357,751)	(3,883,985)
Revisions of previous quantity estimates	Revisions of previous quantity estimates	33,583,837	(22,259,508)	(66,213,586)
Changes in estimated timing of cash flows	Changes in estimated timing of cash flows	(119,428,019)	86,845,188	(139,039,115)
Net change in income taxes	Net change in income taxes	(306,810,205)	(112,496,394)	97,384,365
End of the Year	**End of the Year**	$2,272,113,518	$1,137,364,848	$555,871,253
End of the Year				
End of the Year				

slide1

Exhibit 4.2

DESCRIPTION OF CAPITAL STOCK

General

As of March 7, 2024, we are authorized to issue up to 450,000,000 shares of common stock, with a par value of $0.001 per share, and up to 50,000,000 shares of preferred stock, with a par value of $0.001 per share.

The following is a summary of the key terms and provisions of our common stock. You should refer to the applicable provisions of our Articles of Incorporation (as amended), bylaws (as amended) and the Nevada Revised Statutes for a complete statement of the terms and rights of our capital stock.

Common Stock

Voting. Holders of our common stock are entitled to one vote for each share on all matters submitted to a stockholder vote, except as matters that relate only to a series of our preferred stock. Holders of common stock do not have cumulative voting rights. In general, stockholder action (except for bylaw amendments, which require a majority of shares entitled to vote, and election of directors, which requires a plurality vote) is based on the affirmative vote of a majority of the votes cast. Directors are elected by a plurality of the voting power of the shares present in person or represented by proxy at the meeting and entitled to vote on the election of directors. A vote by the holders of a majority of our outstanding shares of common stock entitled to vote is required to effectuate an amendment to our bylaws. Our Board of Directors is elected annually at the meeting of our stockholders. Each director holds office until the next annual meeting of our stockholders at which his or her term expires and until his or her successor is elected and qualified, or until his or her earlier death, resignation or removal. Any action that the stockholders could take at a meeting may be taken without a meeting if one or more written consents, setting forth the action taken, shall be signed and dated, before or after such action, by the holders of outstanding stock of each voting group entitled to vote thereon having not less than the minimum number of votes with respect to each voting group that would be necessary to authorize or take such action at a meeting at which all voting groups and shares entitled to vote thereon were present and voted. The consent shall be delivered to us for inclusion in the minutes or filing with the corporate records. We will give notice of any action so taken within ten (10) days of the date of such action to those stockholders entitled to vote thereon who did not give their written consent and to those stockholders not entitled to vote thereon.

Dividends. The Board of Directors may from time to time declare, and we may pay, dividends on our outstanding shares of common stock in the manner and upon the terms and conditions provided by the Nevada Revised Statutes. We have not declared or paid any cash dividends on our common stock during the last three years. We currently intend to retain future earnings, if any, to finance the expansion of our business. As a result, we do not anticipate paying any cash dividends in the foreseeable future.

Liquidation. In the event of a liquidation, dissolution or winding up, each outstanding share of common stock entitles its holder to participate pro rata in all assets that remain after payment of liabilities and after providing for any class of stock, if any, having preference over the common stock.

Miscellaneous. Holders of our common stock have no pre-emptive rights, no conversion rights and there are no redemption provisions applicable to our common stock.

Transfer Agent. The transfer agent and registrar for our common stock is Standard Transfer Company.

Listing. Our common stock is listed on the NYSE American under the symbol "REI".

Exhibit 10.25

RING ENERGY, INC.
CHANGE IN CONTROL AND SEVERANCE BENEFIT PLAN

1. Purpose and Effective Date. Ring Energy, Inc. (the "**Company**") has adopted this Change in Control and Severance Benefit Plan (this "**Plan**") to provide for the payment of severance or change in control benefits to Eligible Individuals (as defined below). This Plan was approved by the Board of Directors (the "**Board**") of the Company to be effective as of March 6, 2024 (the "**Effective Date**").

2. Definitions. For purposes of this Plan, the terms listed below will have the meanings specified herein:

(a) "**Accrued Obligations**" means (i) payment to an Eligible Individual of all earned but unpaid Base Salary through the Date of Termination prorated for any partial period of employment; (ii) payment to an Eligible Individual of any unpaid annual incentive payment for the calendar year before the year in which the Date of Termination occurs with the amount determined as either the Actual Full Prior Year Bonus Amount or the Deemed Full Year Bonus Amount, as applicable, provided that an Eligible Individual shall not be entitled to such payment of any annual incentive payment upon a termination of employment by the Company for Cause or if the Eligible Individual terminates his or her employment without Good Reason or without a CIC Good Reason; (iii) payment to an Eligible Individual, in accordance with the terms of the applicable benefit plan of the Company or its Affiliates or to the extent required by law, of any benefits to which such Eligible Individual has a vested entitlement as of the Date of Termination; (iv) payment to an Eligible Individual of any accrued unused vacation; and (v) payment to an Eligible Individual of any approved but not yet reimbursed business expenses incurred in accordance with applicable policies of the Company and its Affiliates, including this Plan.

(b) "**Actual Full Prior Year Bonus Amount**" means if the Eligible Individual was employed for the entire previous year and the Board or Administrator had already finally determined the amount of the Eligible Individual's annual incentive payment amount for the preceding year by the Date of Termination but the Company had not yet paid the Eligible Individual such amount, then such amount will be the amount that was determined by the Board or the Administrator.

(c) "**Administrator**" means the Board, the Compensation Committee of the Board or another Person or committee appointed by the Board to administer this Plan.

(d) "**Affiliate**" means (i) with respect to the Company, any Person or entity that directly or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with, the Company and any predecessor to any such Person or entity; provided, however, that a natural Person shall not be considered an Affiliate; and (ii) with respect to an Eligible Individual, any Person or entity that directly, or through one or more intermediaries, is controlled by such Eligible Individual or members of such Eligible Individual's immediate family.

(e) "**AIP**" means the Eligible Individual's then current "target" annual incentive payment amount.

(f) "**Base Salary**" means an Eligible Individual's annual base salary as of the Notice of Termination (without regard to any reduction in such Base Salary which constitutes Good Reason or CIC Good Reason).

(g) "**Business Opportunities**" means all business ideas, prospects, proposals or other opportunities pertaining to the lease, acquisition, exploration, development, production, gathering or marketing of hydrocarbons and related products and the exploration potential of geographical areas on which hydrocarbon exploration prospects are located, which are conceived or developed by the Eligible Individual during his or her employment with the Company or its Affiliates, or originated by any third party and brought to the attention of the Eligible Individual during his or her employment with the Company or its Affiliates, together with information relating thereto (including, without limitation, geological, geophysical and seismic data and interpretations thereof, whether in the form of maps, charts, logs, seismographs, calculations, summaries, memoranda, opinions or other written or charted means).

(h) "**Cause**" means any of the following:

(i) an Eligible Individual's conviction of, or plea of nolo contendere to, any felony or to any crime or offense causing substantial harm to any of the Company or its Affiliates (whether or not for personal gain) or involving acts of theft, fraud, embezzlement, moral turpitude or similar conduct;

(ii) an Eligible Individual's repeated intoxication by alcohol or other drugs during the performance of his or her duties;

(iii) an Eligible Individual's willful and intentional misuse of any of the funds of the Company or its Affiliates;

(iv) embezzlement against the Company or its Affiliates by an Eligible Individual;

(v) an Eligible Individual's willful and material misrepresentations or concealments in any written reports submitted to any of the Company or its Affiliates;

(vi) an Eligible Individual's willful and intentional material breach of the terms, conditions and covenants of this Plan;

(vii) an Eligible Individual's material failure to follow or comply with the reasonable and lawful written directives of the Board or to otherwise perform his or her duties;

(viii) conduct constituting a material breach by an Eligible Individual of the Company's then current Code of Business Conduct or the Officer Code of Ethics, and any other written policy referenced therein; provided that in each case the Eligible Individual knew or should have known such conduct to be a breach; or

(ix) an Eligible Individual's misconduct, which has or would have if generally known, a materially adverse effect on the mission or reputation of the Company.

(i) "**Change in Control**" or "**CIC**" means each of the following:

(i) a change in the ownership of the Company which occurs on the date any one individual, entity or other person, or a related group of such persons (such person or group, a "**Person**") acquires ownership of stock of the Company that, together with the stock held by such Person, constitutes more than fifty percent (50%) of the total fair market value or total voting power of the stock of the Company (whether such change in ownership occurs by way of a merger, consolidation, purchase or acquisition of stock, or other similar business transaction with the Company); provided, however, that, a Change in Control shall not occur if any Person owns more than 50% of the total fair market value or total voting power of the Company's stock and acquires additional stock;

(ii) a change in the effective control of the Company which occurs on the date a Person acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition) ownership of the Company's stock possessing fifty percent (50%) or more of the total voting power of the stock of the Company; provided, however, if any Person is considered to be in effective control of the Company, the acquisition of additional control of the Company by the same Person will not be considered a Change in Control;

(iii) a change in the effective control of the Company which occurs on the date a majority of the members of the Board of the Company are replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the Board before the date of such appointment or election; or

(iv) a change in the ownership of a substantial portion of the Company's assets which occurs on the date any Person acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition) assets from the Company that have a total gross fair market value equal to or more than fifty percent (50%) of the total gross fair market value of all of the assets of the Company immediately before such acquisition(s); provided, however, that for purposes of this definition, the following will not constitute a change in the ownership of a substantial portion of the Company's assets: (A) a transfer to an entity that is controlled by the Company's stockholders immediately after the transfer, or (B) a transfer of assets by the Company to: (1) a stockholder of the Company (immediately before the asset transfer) in exchange for or with respect to the Company's stock, (2) an entity, 50% or more of the total value or voting power of which is owned, directly or indirectly, by the Company,

(3) a Person, that owns, directly or indirectly, 50% or more of the total value or voting power of all the outstanding stock of the Company, or (4) an entity, at least 50% of the total value or voting power of which is owned, directly or indirectly, by a Person described in clause (3) immediately above; or

(v) the date on which a complete liquidation or dissolution of the Company is consummated.

For purposes of this definition, the term "**gross fair market value**" means the value of the assets of the Company, or the value of the assets being disposed of, determined without regard to any liabilities associated with such assets. Furthermore, for purposes of this definition, Persons will be considered to be acting as a group if they are owners of any entity that enters into a merger, consolidation, purchase or acquisition of stock, or similar business transaction with the Company.

Notwithstanding anything herein to the contrary, with respect to any amounts that constitute deferred compensation under Section 409A, to the extent required to avoid accelerated taxation or penalties, no Change in Control will be deemed to have occurred unless such Change in Control also constitutes a change in control in the ownership or effective control of the Company or a change in the ownership of a substantial portion of the Company's assets under Section 409A.

(j) "**CIC Effective Date**" means the date upon which a Change in Control occurs.

(k) "**CIC Good Reason**" shall exist in the event any of the following actions are taken without an Eligible Individual's written consent, but only if the Date of Termination is within six (6) months before or twenty-four (24) months after a CIC Effective Date:

(i) a material reduction of the Eligible Individual's then current Base Salary;

(ii) failure by the Company to pay the Eligible Individual in full on a current basis any amounts due and owing to the Eligible Individual under any long-term or short-term or other incentive compensation plans, agreements or awards or other action or inaction by the Company constituting a material breach of this Plan or other incentive compensation plans, agreements or awards;

(iii) a material reduction in the Eligible Individual's position, authority, functions, duties or responsibilities compared to the Eligible Individual's position, authority, functions, duties or responsibilities immediately prior to such reduction; or

(iv) the Eligible Individual's primary work location being moved more than fifty (50) miles from the Eligible Individual's primary work location immediately prior to the relocation.

(l) "**CIC Payment Date**" means the date which is the later of the first business day (i) thirty (30) days after the Date of Termination, and (ii) fifteen (15) days after the Release becomes effective and irrevocable in its entirety in accordance with Section 5(e); provided, that if the Date of Termination preceded the CIC Effective Date, then the CIC Payment Date will be the first business day thirty (30) days after the later of (x) the Severance Payment Date and (y) the CIC Effective Date.

(m) "**COBRA**" means the Consolidated Omnibus Budget Reconciliation Act of 1985, as amended from time to time.

(n) "**Code**" means the Internal Revenue Code of 1986, as amended from time to time.

(o) "**Date of Termination**" means (i) if the Eligible Individual's employment with the Company and its Affiliates is terminated by death, the date of such Eligible Individual's death; (ii) if the Eligible Individual's employment is terminated because of the Eligible Individual becoming Disabled, then thirty (30) days after the Notice of Termination is given; or (iii) if (A) the Eligible Individual's employment is terminated by the Company or any of its Affiliates with or without Cause or (B) the Eligible Individual's employment is terminated by the Eligible Individual with or without Good Reason or CIC Good Reason, as applicable, then, in each case, the date specified in the Notice of Termination, which shall comply with the applicable notice requirements set forth herein. Transfer of employment between and among the Company and its Affiliates, by itself, shall not constitute a termination of employment for purposes of this Plan.

(p) "**Deemed Full Year Bonus Amount**" means if the Eligible Individual was employed for the entire previous year but the Date of Termination occurred prior to the Board or the Administrator finally determining the amount of the Eligible Individual's annual incentive payment amount for the preceding year, then the Company's performance will be deemed to have been such that the Eligible Individual would have been awarded 100% of his or her target annual incentive payment amount for that year.

(q) "**Deemed Pro Rata Bonus Amount**" means the amount to be equal to the product of (A) the amount of such Eligible Individual's then current AIP for the year of the Eligible Individual's Date of Termination, times (B) a fraction, (x) the numerator of which shall be the number of calendar days commencing January 1 of such year and ending on the Date of Termination, and (y) the denominator of which shall equal 365).

(r) "**Disability**" or "**Disabled**" means, except as otherwise provided in this Plan, the Eligible Individual is unable to continue providing services by reason of any medically determinable physical or mental impairment which can be expected to result in death or can be expected to last for a continuous period of not less than twelve (12) months. For purposes of this Plan, the determination of Disability shall be made in the sole and absolute discretion of the Administrator.

(s) "**Exchange Act**" means the Securities Exchange Act of 1934, as amended.

(t) "**Good Reason**" shall exist in the event any of the following actions are taken without an Eligible Individual's written consent:

(i) a material reduction of the Eligible Individual's then current Base Salary;

(ii) failure by the Company to pay the Eligible Individual in full on a current basis any amounts due and owing to the Eligible Individual under any long-term or short-term or other incentive compensation plans, agreements or awards or other action or inaction by the Company constituting a material breach of this Plan or other incentive compensation plans, agreements or awards;

(iii) a material reduction in the Eligible Individual's position, authority, functions, duties or responsibilities compared to the Eligible Individual's position, authority, functions, duties or responsibilities immediately prior to such reduction; or

(iv) the Eligible Individual's primary work location being moved more than fifty (50) miles from the Eligible Individual's primary work location immediately prior to the relocation.

(u) "**Intellectual Property**" means all ideas, inventions, discoveries, processes, designs, methods, substances, articles, computer programs and improvements (including, without limitation, enhancements to, or further interpretation or processing of, information that was in the possession of the Eligible Individual prior to the date of this Plan), whether or not patentable or copyrightable, which do not fall within the definition of Business Opportunities, which the Eligible Individual discovers, conceives, invents, creates or develops, alone or with others, during his or her employment with the Company or its Affiliates, if such discovery, conception, invention, creation or development (i) occurs in the course of the Eligible Individual's employment with the Company, (ii) occurs with the use of any of the time, materials or facilities of the Company or its Affiliates, and (iii) in the good faith judgment of the Board or the Administrator, relates or pertains in any material way to the purposes, activities or affairs of the Company or its Affiliates.

(v) "**LTIP**" means collectively, the Company's Long-Term Incentive Plan (as amended and restated from time to time) and the Company's 2021 Omnibus Incentive Plan (as amended and restated from time to time) or any successor equity incentive plan maintained by the Company or successor to the Company.

(w) "**Notice of Termination**" means a notice that indicates the specific termination provision in this Plan relied upon and sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination under the provision so indicated; provided, however, that any failure to provide such detail shall not delay the effectiveness of the termination.

(x) "**Participation Agreement**" means the participation agreement delivered to each Eligible Individual by the Company prior to the Eligible Individual's entry into this Plan evidencing the Eligible Individual's agreement to participate in this Plan and to comply with all terms, conditions and restrictions within this Plan, in substantially the form set forth on Exhibit B attached hereto.

(y) "**Post-Termination Obligations**" means any obligations owed by an Eligible Individual to the Company or any of its Affiliates which survive such Eligible Individual's employment with the Company or its Affiliates, including, without limitation, any obligations and restrictive covenants (including covenants not to compete and not to solicit) set forth herein, in the Release or in an Eligible Individual's Participation Agreement binding on the Eligible Individual.

(z) "**SEC**" means the U.S. Securities and Exchange Commission.

(aa) "**Section 409A**" means Section 409A of the Code and the treasury regulations and administrative guidance issued thereunder.

(ab) "**Section 4999**" means Section 4999 of the Code.

(ac) "**Separation from Service**" means a "separation from service" as such term is defined for purposes of Section 409A.

(ad) "**Severance Obligations**" means the Severance Obligations identified in Section 5(b), Section 5(c) and Section 5(d) of this Plan, as applicable.

(ae) "**Severance Payment Date**" means the date which is the later of the first business day (i) thirty (30) days after the Date of Termination, and (ii) fifteen (15) days after the Release becomes effective and irrevocable in its entirety in accordance with Section 5(e).

(af) "**Stock Incentive Awards**" means all forms of equity-based incentives granted to an Eligible Individual under the Company's award plans, including without limitation stock appreciation rights, restricted stock, stock options, performance shares, performance stock units, and restricted stock units.

(ag) "**Tier 1 Officer**" means an Eligible Individual identified as a "Tier 1 Officer" as determined solely by the Administrator in its absolute discretion and identified in Schedule I attached hereto.

(ah) "**Tier 2 Officer**" means an Eligible Individual identified as a "Tier 2 Officer" as determined solely by the Administrator in its absolute discretion and identified in Schedule I attached hereto.

(ai) "**Tier 3 Employee**" means an Eligible Individual identified as a "Tier 3 Employee" as determined solely by the Administrator in its absolute discretion and identified in Schedule II attached hereto.

(aj) "**Tier**" means the level at which an Eligible Individual is identified immediately prior to the Eligible Individual's termination of employment (without regard to any reduction in such Tier that constitutes a Good Reason or a CIC Good Reason).

3. Administration of this Plan.

(a) Authority of the Administrator. This Plan will be administered by the Administrator. Subject to the express provisions of this Plan (including without limitation Section 10) and applicable law, the Administrator will have the authority, in its sole and absolute discretion, to: (i) adopt, amend, and rescind administrative and interpretive rules and regulations related to this Plan, (ii) delegate its duties under this Plan to such agents as it may appoint from time to time, and (iii) make all other determinations, perform all other acts and exercise all other powers and authority necessary or advisable for administering this Plan, including the delegation of those ministerial acts and responsibilities as the Administrator deems appropriate. The Administrator shall have complete discretion and authority with respect to this Plan and its application except to the extent that discretion is expressly limited by this Plan. The Administrator may correct any defect, supply any omission, or reconcile any inconsistency in this Plan in any manner and to the extent it deems necessary or desirable to carry this Plan into effect, and the Administrator will be the sole and final judge of that necessity or desirability. The determinations of the Administrator on the matters referred to in this Section 3(a) or otherwise arising under this Plan will be final and conclusive.

(b) Manner of Exercise of Authority. Any action of, or determination by, the Administrator will be final, conclusive and binding on all Persons, including the Company, the Company's Affiliates, the Board, the stockholders of the Company, each Eligible Individual, or other Persons claiming rights from or through an Eligible Individual. The express grant of any specific power to the Administrator, and the taking of any action by the Administrator, will not be construed as limiting any power or authority of the Administrator. The Administrator may delegate to officers of the Company, or committees thereof, the authority, subject to such terms as the Administrator will determine, to perform such functions, including administrative functions, as the Administrator may determine. The Administrator may appoint agents to assist it in administering this Plan.

(c) Limitation of Liability. The Administrator will be entitled to, in good faith, rely or act upon any report or other information furnished to the Administrator by any officer or employee of the Company or any of its Affiliates, the Company's legal counsel, independent auditors, consultants or any other agents assisting in the administration of this Plan. The Administrator and any officer or employee of the Company or any of its Affiliates acting at the direction or on behalf of the Administrator will not be personally liable for any action or determination taken or made in good faith with respect to this Plan and will, to the fullest extent permitted by law, be indemnified and held harmless by the Company with respect to any such action or determination.

4. Eligibility. Each employee of the Company or any of its Affiliates eligible to receive the benefits described in this Plan as designated by the Administrator who has entered into a Participation Agreement and who has not been removed from this Plan (collectively, the "**Eligible Individuals**" and each an "**Eligible Individual**").

5. Plan Benefits.

(a) Payment of Accrued Obligations. In the event an Eligible Individual's Date of Termination occurs for any reason, such Eligible Individual shall be entitled to receive the Accrued Obligations. Participation in all benefit plans of the Company and its Affiliates will terminate upon an Eligible Individual's Date of Termination except as otherwise specifically provided in the applicable plan.

(b) Severance Obligations – Unrelated to a Change in Control. In the event an Eligible Individual's employment with the Company and its Affiliates is terminated at any time either (A) by the Company or one of its Affiliates without Cause or (B) by such Eligible Individual resigning such Eligible Individual's employment for Good Reason (other than, in either case, a termination within six (6) months before or the twenty-four (24)-month period following a CIC Effective Date with respect to Tier 1 and Tier 2 Officers or during the six (6) months before or the twelve (12)-month period following the CIC Effective Date with respect to Tier 3 Employees, in any which case shall be governed by Section 5(c) below), the Company (or the Affiliate of the Company that is the employer of the Eligible Individual immediately prior to termination) shall be responsible for the Severance Obligations set forth below; provided that the conditions of Section 5(e), Section 7 and Section 9 have been fulfilled by the Eligible Individual.

(i) *Tier 1 Officers*. The Severance Obligations to a Tier 1 Officer shall be as follows:

(1) on the Severance Payment Date, payment of a single lump sum equal to two (2.0) times the sum of (x) such officer's Base Salary at the highest rate in effect at any time during the thirty-six (36)-month period immediately preceding the Date of Termination and (y) the amount of the officer's most recent AIP, established by the Administrator, prior to the Date of Termination of such officer;

(2) on the Severance Payment Date, payment of an amount equal to one (1.0) times the officer's Deemed Pro Rata Bonus Amount;

(3) on the Severance Payment Date, all Stock Incentive Awards held by such officer will become fully vested at the greater of target or actual performance and be immediately exercisable and all restrictions on such awards shall be deemed removed (other than as may be required under applicable securities laws); and

(4) if and to the extent permitted under applicable law and without any penalty to the Company or the officer, during the twenty-four (24)-month period commencing as of the date such officer is eligible to elect and timely elects to continue coverage for such officer and such officer's eligible dependents under the Company's or an Affiliate's group health plan pursuant to COBRA or similar state law, the Company (or the Affiliate of the Company that is the officer's employer immediately prior to termination) shall reimburse such officer for the amount such officer pays to effect and continue such coverage, with any such reimbursement payable for the period prior to the Severance Payment Date immediately following the Date of Termination being payable on the Severance Payment Date and any other such reimbursement payable being paid on a monthly basis thereafter.

(ii) *Tier 2 Officers*. The Severance Obligations to a Tier 2 Officer shall be as follows:

(1) on the Severance Payment Date, payment of a single lump sum equal to one (1.0) times the sum of (x) such officer's Base Salary at the highest rate in effect at any time during the thirty-six (36)-month period immediately preceding the Date of Termination and (y) the amount of the officer's most recent AIP, established by the Administrator, prior to the Date of Termination of such officer;

(2) on the Severance Payment Date, payment of an amount equal to one (1.0) times such officer's Deemed Pro Rata Bonus Amount;

(3) on the Severance Payment Date, all Stock Incentive Awards held by such officer will become fully vested at the greater of target or actual performance and be immediately exercisable and all restrictions on such awards shall be deemed removed (other than as may be required under applicable securities laws); and

(4) if and to the extent permitted under applicable law and without any penalty to the Company or the officer, during the eighteen (18)-month period commencing as of the date such officer is eligible to elect and timely elects to continue coverage for such officer and such officer's eligible dependents under the Company's or an Affiliate's group health plan pursuant to COBRA or similar state law, the Company (or the Affiliate of the Company that is the officer's employer immediately prior to termination) shall reimburse such officer for the amount such officer pays to effect and continue such coverage, with any such reimbursement payable for the period prior to the Severance Payment Date immediately following the Date of Termination being payable on the Severance Payment Date and any other such reimbursement payable being paid on a monthly basis thereafter.

(iii) *Tier 3 Employee*. The Severance Obligations to a Tier 3 Employee shall be as set forth in Schedule III.

(c) Severance Obligations – Related to a Change in Control. In the event an Eligible Individual is employed by the Company or one of its Affiliates on the CIC Effective Date or during the six (6) months prior to the CIC Effective Date and the Eligible Individual (i) resigns such Eligible Individual's employment with the Company and its Affiliates for a CIC Good Reason or (ii) is terminated by the Company and its Affiliates without Cause, in each case, at any time within six (6) months before or the twenty-four (24) month period following the CIC Effective Date with respect to Tier 1 and Tier 2 Officers and at any time within the six (6) months before or the twelve (12)-month period following the CIC Effective Date with respect to Tier 3 Employees, then, the Company (or the Affiliate of the Company that is the employer of the Eligible Individual immediately prior to termination) shall provide the Severance Obligations set forth below, provided that the conditions of Section 5(e), Section 7 and Section 9 have been fulfilled. Notwithstanding the foregoing, in the event that an Eligible Individual's Separation of Service occurs by reason of the Eligible Individual's refusal to accept an offer of employment (including continued employment with the Company or any of its Affiliates) in connection with a Change in Control or other corporate transaction and if such offer of employment would not constitute a basis for a CIC Good Reason, then the Eligible Individual shall not be entitled to Severance Obligations under this Plan pursuant to this Section 5(c).

(i) *Tier 1 Officers*. The Severance Obligations to a Tier 1 Officer shall be as follows:

(1) on the CIC Payment Date, payment of a single lump sum equal to three (3.0) times the sum of (x) such officer's Base Salary at the highest rate in effect at any time during the thirty-six (36)-month period immediately preceding the Date of Termination and (y) the amount of the officer's most recent AIP, established by the Administrator, prior to the Date of Termination of such officer;

(2) on the CIC Payment Date, payment of an amount equal to one (1.0) times such officer's Deemed Pro Rata Bonus Amount;

(3) on the CIC Payment Date, all Stock Incentive Awards held by such officer will become fully vested at the greater of target or actual performance and be immediately exercisable and all restrictions on such awards shall be deemed removed (other than as may be required under applicable securities laws); and

(4) if and to the extent permitted under applicable law and without any penalty to the Company or the officer, during the twenty-four (24)-month period commencing as of the date such officer is eligible to elect and timely elects to continue coverage for such officer and such officer's eligible dependents under the Company's or an Affiliate's group health plan pursuant to COBRA or similar state law, the Company (or the Affiliate of the Company that is the officer's employer immediately prior to termination) shall reimburse such officer for the amount such officer pays to effect and continue such coverage, with any such reimbursement payable for the period prior to the CIC Payment Date immediately following the Date of Termination being payable on the CIC Payment Date and any other such reimbursement payable being paid on a monthly basis thereafter. Notwithstanding the foregoing, the benefits described in this subsection shall be discontinued by the Company prior to the end of the period provided in this subsection if such officer receives substantially similar benefits from a subsequent employer.

(ii) *Tier 2 Officers*. The Severance Obligations to a Tier 2 Officer shall be as follows:

(1) on the CIC Payment Date, payment of a single lump sum equal to two (2.0) times the sum of (x) such officer's Base Salary at the highest rate in effect at any time during the thirty-six (36)-month period immediately preceding the Date of Termination and (y) the amount of the officer's most recent AIP, established by the Administrator, prior to the Date of Termination of such officer;

(2) on the CIC Payment Date, payment of an amount equal to one (1.0) times such Deemed Pro Rata Bonus Amount;

(3) on the CIC Payment Date, all Stock Incentive Awards held by such officer will become fully vested at the greater of target or actual performance and be immediately exercisable and all restrictions on such awards shall be deemed removed (other than as may be required under applicable securities laws); and

(4) if and to the extent permitted under applicable law and without any penalty to the Company or the officer, during the eighteen (18)-month period commencing as of the date such officer is eligible to elect and timely elects to continue coverage for such officer and such officer's eligible dependents under the Company's or an Affiliate's group health plan pursuant to COBRA or similar state law, the Company (or the Affiliate of the Company that is the officer's employer immediately prior to termination) shall reimburse such officer for the amount such officer pays to effect and continue such coverage, with any such reimbursement payable for the period prior to the CIC Payment Date immediately following the Date of Termination being payable on the CIC Payment Date and any other such reimbursement payable being paid on a monthly basis thereafter. Notwithstanding the foregoing, the benefits described in this subsection shall be discontinued by the Company prior to the end of the period provided in this subsection if such officer receives substantially similar benefits from a subsequent employer.

(iii) *Tier 3 Employees*. The Severance Obligations to a Tier 3 Employee shall be as set forth in Schedule III.

(iv) The foregoing notwithstanding, if the Date of Termination preceded the Change in Control, the amount of Severance Obligations to which the Eligible Individual will be entitled under this Section 5(c) will be the difference between the Severance Obligations already paid to the Eligible Individual, if any, under Section 5(b) and the Severance Obligations to be paid under this Section 5(c) (the "**Additional Severance Obligations**"). For the sake of clarity, any Severance Obligations payable under Section 5(b) will be payable on the Severance Payment Date, and any Severance Obligations payable under Section 5(c) and any Additional Severance Obligations will be payable on the CIC Payment Date.

(d) Severance Obligations – Death or Disability. In the event an Eligible Individual's employment with the Company and its Affiliates is terminated by death or Disability, the Company (or the Affiliate of the Company that is the employer of the Eligible Individual immediately prior to termination) shall provide Severance Obligations set forth below; provided that the conditions of Section 5(e), Section 7 and Section 9 have been fulfilled.

(i) *Eligible Individuals*. The Severance Obligations to an Eligible Individual shall be as follows:

(1) in the event of the Eligible Individual's termination by reason of Disability or death, the Eligible Individual will continue to receive his or her Base Salary in effect immediately prior to the Date of Termination and participate in applicable employee benefit plans or programs of the Company (on an equivalent basis to those employee benefit plans or programs provided therefore, including equity based programs) through the Date of Termination, subject to offset dollar-for-dollar by the amount of any disability income payments provided to the Eligible Individual under any Company disability policy or program funded by the Company;

(2) on the Severance Payment Date, all Stock Incentive Awards held by the Eligible Individual will become fully vested and immediately exercisable and all restrictions thereon shall be removed (other than as may be required under applicable securities laws); and

(3) in addition, in the event of death of the Eligible Individual, if and to the extent permitted under applicable law and without any penalty to the Company or the Eligible Individual, during the twelve (12)-month period commencing as of the date such Eligible Individual's spouse and eligible dependents are eligible to elect and timely elect to continue coverage for such Eligible Individual's eligible dependents under the Company's or an Affiliate's group health plan pursuant to COBRA or similar state law, the Company (or the Affiliate of the

Company that is the Eligible Individual's employer immediately prior to termination) shall reimburse such Eligible Individual's eligible dependents for the amount such Eligible Individual's eligible dependents pay to effect and continue such coverage, with any such reimbursement payable for the period prior to the Severance Payment Date immediately following the Date of Termination being payable on the Severance Payment Date and any other such reimbursement payable being paid on a monthly basis thereafter.

Thereafter, the Company will have no further obligation to the Eligible Individual or his or her estate under this Plan, other than for payment of any amounts accrued and vested under any employee benefit plans or programs of the Company and any payments or benefits required to be made or provided under applicable law.

(e) Release. Notwithstanding Section 5(b) or Section 5(c) of this Plan, in no event shall an Eligible Individual be entitled to the Severance Obligations unless such Eligible Individual (i) tenders his or her resignation as a member of the Board and of the board of directors, management committee or other management appointment of any Affiliate (in each case, to the extent applicable) effective as of the Date of Termination (the "**Resignation**"), and (ii) executes a General Release in a form and substance approved by the Administrator (the "**Release**") substantially similar to the Release attached hereto as Exhibit A, with any additional customary terms as the Administrator may deem appropriate in the circumstances, and such Release is not revoked. Notwithstanding Section 5(d) of this Plan, in no event shall an Eligible Individual or the estate of the Eligible Individual be entitled to the Severance Obligations unless such Eligible Individual (or, if applicable, the Eligible Individual's personal representative or estate) executes the Release, with any additional customary terms as the Administrator may deem appropriate in the circumstances, and such Release is not revoked. The Eligible Individual or the Eligible Individual's estate shall be eligible for the Severance Obligations only if the executed Release is returned to the Company and becomes irrevocable within sixty (60) days after the Date of Termination. Until the Release has become irrevocable, any such Severance Obligations shall not be provided by the Company or any of its Affiliates. If an Eligible Individual fails to return the Resignation so that it would, if accepted, be effective upon the Date of Termination, or if an Eligible Individual (or, if applicable, the Eligible Individual's personal representative or estate) fails to return the Release to the Company in sufficient time so that the Release becomes irrevocable within sixty (60) days after the Date of Termination, such Eligible Individual's rights to the Severance Obligations shall be forfeited.

(f) Severance Obligations Not Includable for Eligible Individual Benefits Purposes. Except to the extent the terms of any applicable benefit plan, policy or program provide otherwise, any benefit programs of the Company that take into account the Eligible Individual's income will exclude any and all Severance Obligations provided under this Plan.

6. Parachute Payment Limitations.

(a) Notwithstanding anything in this Plan to the contrary, if any payment or benefit received or to be received by the Eligible Individual in connection with a Change in Control or the termination of the Eligible Individual's employment (whether pursuant to the terms of this Plan or any other plan, arrangement or agreement with the Company, any other entity whose actions result in a Change in Control or any entity affiliated with the Company) (all such payments and benefits, including the Severance Obligations pursuant to Section 5(c), being hereinafter referred to as the "**Total Payments**") would constitute an "excess parachute payment" under Section 280G(a) of the Code (or any successor provision thereto) and would be subject (in whole or part), to the excise tax imposed under Section 4999 of the Code (or any successor provision thereto), including any similar state or local tax and any related interest or penalties (collectively, the "**Excise Tax**"), then prior to making the Total Payments, a calculation shall be made comparing (i) the After-Tax Value (as defined below) to the Eligible Individual of the Total Payments after payment of the Excise Tax to (ii) the After-Tax Value to the Eligible Individual if the Total

Payments are limited to the extent necessary to avoid being subject to the Excise Tax. Only if the amount calculated under clause (i) above is less than the amount under clause (ii) above will the Total Payments be reduced to the minimum extent necessary to ensure that no portion of the Total Payments is subject to the Excise Tax.

(b) For purposes of this Plan, "**After-Tax Value**" shall mean the present value of the Total Payments reduced by all federal, state, local and foreign income, excise and employment taxes applicable to such payments. Furthermore, the terms "**excess parachute payment**" and "**parachute payments**" shall have the meanings assigned to them in Section 280G of the Code, and such "parachute payments" shall be valued as provided therein. All determinations and calculations required to be made under this Section 6 shall be made by the Company's independent accountants (at the Company's expense), in consultation with the Eligible Individual and subject to the reasonable right of the Eligible Individual's representative(s) to review and comment on such calculations prior to final determination. The parties recognize that the actual implementation of the provisions of this Section 6 may be complex and agree to deal with each other in good faith to resolve any questions or disagreements arising hereunder.

(c) The Total Payments shall be reduced, as applicable, in a manner that maximizes the Eligible Individual's economic position. In applying this principle, the reduction shall be made in a manner consistent with the requirements of Section 409A, and where two economically equivalent amounts are subject to reduction but payable at different times, such amounts shall be reduced on a pro rata basis but not below zero.

7. Conditions to Receipt of Severance Obligations.

(a) Compliance with Post-Termination Obligations. Notwithstanding anything contained in this Plan to the contrary, the Company and its Affiliates shall have the right to cease providing any part of the Severance Obligations, and the Eligible Individual shall be required to immediately repay the Company and its Affiliates for any Severance Obligations already provided, but all other provisions of this Plan shall remain in full force and effect, if such Eligible Individual has been determined, pursuant to the dispute resolution provisions hereof, not to have fully complied with such Eligible Individual's Post-Termination Obligations during the Restrictive Period or longer, as may be the case.

(b) Separation from Service Required. Notwithstanding anything contained in this Plan to the contrary, the Eligible Individual shall be entitled to Severance Obligations only if such Eligible Individual's termination of employment constitutes a Separation from Service.

8. Termination.

(a) Notice of Termination. Any termination of an Eligible Individual's employment with the Company and its Affiliates (other than termination as a result of death) shall be communicated by written Notice of Termination to, (i) in the case of termination by an Eligible Individual, the Company or one of its Affiliates and (ii) in the case of termination by the Company and its Affiliates, the Eligible Individual. Unless an Eligible Individual has a separate employment agreement, such Eligible Individual shall be deemed to be an employee "at will" of the Company.

(b) Death. An Eligible Individual's employment with the Company and its Affiliates shall terminate immediately upon such Eligible Individual's death.

(c) Disability. An Eligible Individual's employment with the Company and its Affiliates shall terminate fifteen (15) days after Notice of Termination is given by the Company or its Affiliates.

(d) For Cause.

(i) Subject to Section 8(d)(ii), the Company and its Affiliates shall be entitled to terminate an Eligible Individual's employment with the Company and its Affiliates immediately for any Cause.

(ii) If the Administrator determines, in its sole discretion, that a cure is possible and appropriate, the Company or the applicable Affiliate will give an Eligible Individual being terminated for Cause written notice of the acts or omissions constituting Cause and no termination of such Eligible Individual's employment with the Company and its Affiliates for Cause shall occur unless and until such Eligible Individual fails to cure such acts or omissions within fifteen (15) days following the receipt of such written notice. If the Administrator determines, in its sole discretion, that a cure is not possible or appropriate, an Eligible Individual being terminated for Cause shall have no notice or cure rights before such Eligible Individual's employment with the Company and its Affiliates is terminated for Cause.

(e) Without Cause. The Company and its Affiliates shall be entitled to terminate an Eligible Individual's employment with the Company for any reason, at any time by providing written notice to such Eligible Individual that the Company and its Affiliates is terminating such Eligible Individual's employment with the Company and its Affiliates without Cause.

(f) With Good Reason.

(i) Subject to Section 8(f)(ii), an Eligible Individual shall be permitted to terminate such Eligible Individual's employment with the Company and its Affiliates for any Good Reason or CIC Good Reason, as applicable.

(ii) To exercise an Eligible Individual's right to terminate such Eligible Individual's employment for Good Reason or CIC Good Reason, as applicable, such Eligible Individual must provide written notice to the Company or one of its Affiliates of such Eligible Individual's belief that Good Reason

or CIC Good Reason, as applicable, exists within ninety (90) days of the initial existence of the condition(s) giving rise to such Good Reason or CIC Good Reason, as applicable, and such notice shall describe the conditions believed to constitute Good Reason or CIC Good Reason, as applicable. The Company and its Affiliates shall have thirty (30) days to remedy the Good Reason or CIC Good Reason, as applicable, condition(s) (the "**Cure Period**"). If the condition(s) are not remedied during such Cure Period, such Eligible Individual may terminate such Eligible Individual's employment with the Company and its Affiliates for Good Reason or CIC Good Reason, as applicable, by delivering a Notice of Termination to the Company; provided, however, that such termination must occur no later than ten (10) days after the conclusion of the Cure Period; otherwise, such Eligible Individual is deemed to have accepted the condition(s), or the Company's and its Affiliates correction of such condition(s), that may have given rise to the existence of such Good Reason or CIC Good Reason, as applicable.

(g) Without Good Reason. An Eligible Individual shall be entitled to terminate such Eligible Individual's employment with the Company and its Affiliates at any time by providing thirty (30) days written Notice of Termination to the Company or one of its Affiliates and stating that such termination is without Good Reason or CIC Good Reason; provided, however, that notwithstanding anything to the contrary contained herein, the Company and its Affiliates shall be under no obligation to continue to employ such Eligible Individual for such thirty (30)-day period.

(h) Suspension of Duties. Notwithstanding the foregoing provisions of this Section 8, the Company and its Affiliates may, to the extent doing so would not result in the Eligible Individual's Separation from Service, suspend an Eligible Individual from performing such Eligible Individual's duties, responsibilities, and authorities (including, without limitation, such Eligible Individual's duties, responsibilities and authorities as a member of the Board or the board of directors of any Affiliate) following the delivery by such Eligible Individual of a Notice of Termination providing for such Eligible Individual's resignation, or following delivery by the Company or one of its Affiliates of a Notice of Termination providing for the termination of such Eligible Individual's employment for any reason; provided, however, that during the period of suspension (which shall end on or before the Date of Termination), and subject to the legal rules applicable to any Company benefit plans under Section 401(a) of the Code and the rules applicable to nonqualified deferred compensation plans under Section 409A, such Eligible Individual shall continue to be treated as employed by the Company and its Affiliates for other purposes, and such Eligible Individual's rights to compensation or benefits shall not be reduced by reason of the suspension; and provided, further, that any such suspension shall not serve as a basis for Good Reason or CIC Good Reason, as applicable, and shall not affect the determination of whether the resignation was for Good Reason or CIC Good Reason, as applicable, or without Good Reason or CIC Good Reason, as applicable, or whether the termination was for Cause or without Cause. The Company and its Affiliates may suspend an Eligible Individual with pay pending an investigation authorized by the Company or any of its Affiliates or a governmental authority in order to determine whether such Eligible Individual has engaged in acts or omissions constituting Cause, and in such case the paid suspension shall not constitute a termination of such Eligible Individual's employment with the Company and its Affiliates; provided, however, that such suspension shall not continue past the time that the Eligible Individual would incur a Separation from Service (at such point, the Company shall either terminate the Eligible Individual in accordance with this Plan or have the Eligible Individual return to active employment).

9. Restrictive Covenants. By executing a Participation Agreement, the Eligible Individual agrees to the following provisions:

(a) Confidential Information. The Eligible Individual hereby acknowledges that in connection with his or her employment by the Company and his or her participation in this Plan, he or she will be exposed to and may obtain certain Confidential Information (as defined below) (including, without limitation, procedures, memoranda, notes, records and customer and supplier lists whether such information has been or is made, developed or compiled by the Eligible Individual or otherwise has been or is made available to him or her) regarding the business and operations of the Company and its Affiliates. The Eligible Individual further acknowledges that such Confidential Information is unique, valuable, considered trade secrets and deemed proprietary by the Company. For purposes of this Plan, "**Confidential Information**" includes, without limitation, any information heretofore or hereafter acquired, developed or used by the Company or its Affiliates relating to Business Opportunities or Intellectual Property or other geological, geophysical, economic, financial or management aspects of the business, operations, properties or prospects of the Company or its Affiliates, whether oral or in written form. The Eligible Individual agrees that all Confidential Information is and will remain the property of the Company or its Affiliates, as the case may be. The Eligible Individual further agrees, except for disclosures occurring in the good faith performance of his or her duties for the Company or its Affiliates, during his or her employment with the Company or its Affiliates, the Eligible Individual will hold in the strictest confidence all Confidential Information, and will not, both during his or her employment with the Company or its Affiliates and after the Date of Termination, directly or indirectly, duplicate, sell, use, lease, commercialize, disclose or otherwise divulge to any Person or entity any portion of the Confidential Information or use any Confidential Information, directly or indirectly, for his or her own benefit or profit or allow any Person, entity or third party, other than the

Company or its Affiliates and authorized Eligible Individuals of the same, to use or otherwise gain access to any Confidential Information. The Eligible Individual will have no obligation under this Plan with respect to any information that becomes generally available to the public other than as a result of a disclosure by the Eligible Individual or his or her agent or other representative or becomes available to the Eligible Individual on a non-confidential basis from a source other than the Company or its Affiliates. Further, the Eligible Individual will have no obligation under this Plan to keep confidential any of the Confidential Information to the extent that a disclosure of it is required by law or is consented to by the Company; provided, however, that if and when such a disclosure is required by law, the Eligible Individual promptly will provide the Company with notice of such requirement, so that the Company may seek an appropriate protective order. The Eligible Individual understands that nothing contained in this Plan limits the Eligible Individual's ability to file a charge or complaint with the Equal Employment Opportunity Commission, the National Labor Relations Board, the Occupational Safety and Health Administration, the SEC or any other federal, state or local governmental agency or commission (collectively, "**Government Agencies**"). The Eligible Individual further understands that this Plan does not limit the Eligible Individual's ability to communicate with any Government Agencies or otherwise participate in any investigation or proceeding that may be conducted by any Government Agency, including providing documents or other information, without notice to the Company. This Plan does not limit the Eligible Individual's right to receive an award for information provided to any Government Agencies.

(b) Return of Property. The Eligible Individual agrees to deliver promptly to the Company, upon termination of his or her employment with the Company or its Affiliates, or at any other time when the Company so requests, all documents relating to the business of the Company or its Affiliates, including without limitation: all computers, telephones, access cards, geological and geophysical reports and related data such as maps, charts, logs, seismographs, seismic records and other reports and related data, calculations, summaries, memoranda and opinions relating to the foregoing, production records, electric logs, core data, pressure data, lease files, well files and records, land files, abstracts, title opinions, title or curative matters, contract files, notes, records, drawings, manuals, correspondence, financial and accounting information, customer lists, statistical data and compilations, patents, copyrights, trademarks, trade names, inventions, formulae, methods, processes, agreements, contracts, manuals or any documents relating to the business of the Company or its Affiliates and all copies thereof and therefrom; provided, however, that the Eligible Individual will be permitted to retain copies of any documents or materials of a personal nature or otherwise related to the Eligible Individual's rights under this Plan, copies of this Plan and any attendant or ancillary documents.

(c) Non-Compete Obligations. In exchange for the Eligible Individual's participation in this Plan, which the Eligible Individual agrees is good and valuable consideration, the Eligible Individual agrees to the following restrictions:

(i) *Non-Compete Obligations During Employment with the Company.* The Eligible Individual agrees that during his or her employment with the Company or its Affiliates:

(1) the Eligible Individual will not, other than through the Company, engage or participate in any manner, whether directly or indirectly through any family member or as an Eligible Individual, employer, consultant, agent, principal, partner, more than one percent (1%) shareholder, officer, director, licensor, lender, lessor or in any other individual or representative capacity, in any business or activity which is engaged in leasing, acquiring, exploring, developing, producing, gathering or marketing hydrocarbons and related products ("**Competing Business**"); provided that the foregoing shall not be deemed to restrain the participation by the Eligible Individual's spouse in any capacity set forth above in any business or activity engaged in any such activity and provided further that the Company may, in good faith, take such reasonable action with respect to the Eligible Individual's performance of his or her duties, responsibilities and authorities as it deems necessary and appropriate to protect its legitimate business interests with respect to any actual or apparent conflict of interest reasonably arising from or out of the participation by Eligible Individual's spouse in any such competitive business or activity; and

(2) all investments made by the Eligible Individual (whether in his or her own name or in the name of any family members or other nominees or made by the Eligible Individual's controlled affiliates), which relate to the leasing, acquisition, exploration, development, production, gathering or marketing of hydrocarbons and related products will be made solely through the Company, other than as may be approved by the Board; and the Eligible Individual will not (directly or indirectly through any family members or other Persons), and will not permit any of his or her controlled affiliates to: (A) invest or otherwise participate alongside the Company or its Affiliates in any Business Opportunities, or (B) invest or otherwise participate in any business or activity relating to a Business Opportunity, regardless of whether any of the Company or its Affiliates ultimately participates in such business or activity, in either case, except

through the Company. Notwithstanding the foregoing, nothing in this Section 9(c) shall be deemed to prohibit the Eligible Individual or any family member from owning, or otherwise having an interest in, less than one percent (1%) of any publicly owned entity or three percent (3%) or less of any private equity fund or similar investment fund that invests in any business or activity engaged in any of the activities set forth above; provided that Eligible Individual has no active role with respect to any investment by such fund in any entity.

(ii) *Non-Compete Obligations After Date of Termination.* The Eligible Individual agrees that the Eligible Individual will not engage or participate in any manner, whether directly or indirectly, through any family member or other Person or as an employee, employer, consultant, agent principal, partner, more than one percent (1%) shareholder, officer, director, licensor, lender, lessor or in any other individual or representative capacity during the one (1) year period following the Date of Termination (the "**Restricted Period**"), in any Competing Business within the boundaries of, or within a two-mile radius of the boundaries of, any mineral property interest of any of the Company or its Affiliates (including, without limitation, a mineral lease, overriding royalty interest, production payment, net profits interest, mineral fee interest or option or right to acquire any of the foregoing, or an area of mutual interest as designated pursuant to contractual agreements between the Company and any third party) or any other property on which any of the Company or its Affiliates has an option, right, license or authority to conduct or direct exploratory activities, such as three-dimensional seismic acquisition or other seismic, geophysical and geochemical activities (but not including any preliminary geological mapping), as of the Date of Termination or as of the end of the six (6) month period following such Date of Termination; provided that, this Section 9(c)(ii) will not preclude the Eligible Individual from making investments in securities of oil and gas companies which are registered on a national stock exchange, if (1) the aggregate amount owned by the Eligible Individual and all family members and Affiliates does not exceed five percent (5%) of such company's outstanding securities, and (2) the aggregate amount invested in such investments by the Eligible Individual and all family members and Affiliates after the date hereof does not exceed $1,000,000.

(iii) *Six Months Following Change in Control Termination.* The Restricted Period for an Eligible Individual will be six (6) months rather than one (1) year in the event that the Eligible Individual receives any Severance Obligations pursuant to Section 5(c).

Notwithstanding the foregoing, nothing in this Section 9(c) shall be deemed to restrain the participation by the Eligible Individual's spouse in any capacity set forth above in any business or activity described above.

(d) <u>Non-Solicitation</u>.

(i) *Non-Solicitation Other than Following a Change in Control Termination*. During the Eligible Individual's employment with the Company or its Affiliates and during the Restricted Period, the Eligible Individual will not, whether for his or her own account or for the account of any other Person (other than the Company or Affiliates), (1) intentionally solicit, endeavor to entice away from the Company or its Affiliates, or otherwise interfere with the relationship of the Company or its Affiliates with, any Person who is employed by the Company or its Affiliates (including any independent sales representatives or organizations), or (2) using Confidential Information, solicit, endeavor to entice away from the Company or its Affiliates, or otherwise interfere with the relationship of the Company or its Affiliates with, any client or customer of the Company or its Affiliates in direct competition with the Company.

(ii) *Not Applicable Following Change in Control Termination.* The Eligible Individual will not be subject to the covenants contained in Section 9(d)(i) and such covenants will not be enforceable against the Eligible Individual in the event that the Eligible Individual receives any Severance Obligations pursuant to Section 5(c).

(e) <u>Assignment of Developments</u>. The Eligible Individual assigns and agrees to assign without further compensation to the Company and its successors, assigns or designees, all of the Eligible Individual's right, title and interest in and to all Business Opportunities and Intellectual Property, and further acknowledges and agrees that all Business Opportunities and Intellectual Property constitute the exclusive property of the Company.

(f) <u>Injunctive Relief</u>. The Eligible Individual acknowledges that a breach of any of the covenants contained in this Section 9 may result in material, irreparable injury to the Company for which there is no adequate remedy at law, that it will not be possible to measure damages for such injuries precisely and that, in the event of such a breach or threat of breach, the Company will be entitled to obtain a temporary restraining order and/

or a preliminary or permanent injunction restraining the Eligible Individual from engaging in activities prohibited by this Section 9 or such other relief as may be required to specifically enforce any of the covenants in this Section 9.

(g) Adjustment of Covenants. The parties consider the covenants and restrictions contained in this Section 9 to be reasonable. However, if any such covenant or restriction or part thereof is found to be void or unenforceable and would have been valid had some part of it been deleted or had its scope of application been modified, such covenant, restriction, or part thereof will be deemed to have been applied with such modification as would be necessary and consistent with the intent of the parties to have made it valid, enforceable and effective.

10. General Provisions.

(a) Taxes. The Company and its Affiliates are authorized to withhold from any payments made hereunder amounts of withholding and other taxes due or potentially payable in connection therewith, and to take such other action as the Company and its Affiliates may deem advisable to enable the Company, its Affiliates and Eligible Individuals to satisfy obligations for the payment of withholding taxes and other tax obligations relating to any payments made under this Plan.

(b) Offsets and Substitutions. Pursuant to Treasury Regulation Section 1.409A-3(j)(4)(xiii), the Company and its Affiliates may set off against, and each Eligible Individual authorizes the Company and its Affiliates to deduct from, any payments due to such Eligible Individual, or to such Eligible Individual's estate, heirs, legal representatives or successors, any amounts which may be due and owing to the Company or an Affiliate by such Eligible Individual, arising in the ordinary course of business whether under this Plan or otherwise. To the extent that any amounts would otherwise be payable (or benefits would otherwise be provided) to an Eligible Individual under another plan of the Company or its Affiliates or an agreement with the Eligible Individual and the Company or its Affiliates, including a change in control plan or agreement, an offer letter or letter agreement, or to the extent that an Eligible Individual moves between Tiers, and to the extent that such other payments or benefits or the Severance Obligations provided under this Plan are subject to Section 409A, this Plan shall be administered to ensure that no payment or benefit under this Plan will be (i) accelerated in violation of Section 409A or (ii) further deferred in violation of Section 409A.

(c) Term of this Plan; Amendment and Termination.

(i) Prior to a Change in Control, this Plan may be amended or modified in any respect, and may be terminated, in any such case, by resolution adopted by the Administrator and a majority of the Board; provided, however, that (1) any such amendment, modification or termination made prior to a Change in Control that materially adversely affects the benefits or protections of any Eligible Individual must be unanimously approved by the Board, including any independent director(s) but excluding any directors who are Eligible Individuals under this Plan, and such amendment, modification or termination will not be effective for a period of twenty-four (24) months after such approval by the Board, and (2) no such amendment, modification or termination that the Administrator determines in its sole discretion is required to be adopted as a condition to the consummation of Change in Control pursuant to the request of a third party who effectuates a Change in Control that would adversely affect the benefits or protections hereunder of any Eligible Individual as of the date such amendment, modification or termination is adopted shall be effective as it relates to such Eligible Individual. For a period of twenty-five (25) months following the CIC Effective Date, this Plan may not be amended or modified in any manner that would in any way adversely affect the benefits or protections provided hereunder to any Eligible Individual under this Plan on the date the Change in Control occurs unless agreed in writing by the Eligible Individual.

(i) Notwithstanding the provisions of Section 10(c)(i) above, the Company may terminate and liquidate this Plan in accordance with the provisions of Section 409A.

(ii) Notwithstanding the foregoing, no amendment, modification or termination of this Plan shall adversely affect any Eligible Individual's entitlement to payments under this Plan for qualifying terminations of employment occurring prior to such amendment, modification or termination (other than as required to permit termination of this Plan in accordance with Section 409A), nor shall such amendment, modification or termination relieve the Company of its obligation to pay vested benefits to Eligible Individuals who experienced a qualifying termination of employment prior to the date of such amendment, modification or termination as otherwise set forth herein, except as otherwise consented to by such Eligible Individual.

(d) Successors. This Plan will be binding upon any successor to the Company, its assets, its businesses or its interest (whether as a result of the occurrence of a Change in Control or otherwise), in the same manner and to the same extent that the Company would be obligated under this Plan if no succession had taken place. In the case of any transaction in which a successor would not by the foregoing provision or by operation of law be bound by this Plan, the Company shall require any successor to the Company to expressly and unconditionally assume this Plan in writing and honor the obligations of the Company hereunder, in the same manner and to the same extent that the Company would be required to perform if no succession had taken place. Neither this Plan nor any right or obligation hereunder of any Eligible Individual may be assigned or delegated without the prior written consent of the Company; provided, however, that an Eligible Individual may direct payment of any benefits that will accrue upon death. An Eligible Individual shall not have any right to pledge, hypothecate, anticipate or in any way create a lien upon any payments or other benefits provided under this Plan; and no benefits payable under this Plan shall be assignable in anticipation of payment either by voluntary or involuntary acts, or by operation of law, except by will or pursuant to the laws of descent and distribution. This Plan shall not confer any rights or remedies upon any Person other than the Company, its Affiliates and the Eligible Individuals and their respective successors and permitted assigns.

(e) Notices. All notices and other communications required hereunder shall be in writing and shall be delivered personally or mailed by registered or certified mail, return receipt requested, or by overnight express courier service. In the case of an Eligible Individual, mailed notices shall be addressed at the home address which the Eligible Individual most recently communicated to the Company in writing. In the case of the Company, mailed notices shall be addressed to the Administrator and the Company's Chief Executive Officer.

(f) Unfunded Obligation. All benefits due an Eligible Individual under this Plan are unfunded and unsecured and are payable out of the general funds of the Company and its Affiliates.

(g) Directed Payments. If any Eligible Individual is determined by the Administrator to be Disabled, the Administrator may cause the payment or payments becoming due to such Eligible Individual to be made to another Person for such Person's benefit without responsibility on the part of the Administrator or the Company and its Affiliates to follow the application of such funds.

(h) Limitation on Rights Conferred Under Plan. Neither this Plan nor any action taken hereunder will be construed as (i) giving an Eligible Individual the right to continue in the employ or service of the Company or any Affiliate; (ii) interfering in any way with the right of the Company or any Affiliate to terminate an Eligible Individual's employment or service at any time; or (iii) giving an Eligible Individual any claim to be treated uniformly with other employees of the Company or any of its Affiliates. The provisions of this Plan supersede any oral statements made by any employee, officer, or Board member of the Company or any of its Affiliates regarding eligibility, severance payments and benefits.

(i) Governing Law. All questions arising with respect to the provisions of this Plan and payments due hereunder will be determined by application of the laws of the State of Texas, without giving effect to any conflict of law provisions thereof, except to the extent Texas law is preempted by federal law.

(j) Dispute Resolution. Any and all disputes, claims or controversies arising out of or relating to this Plan (i) shall be brought by an Eligible Individual in such Eligible Individual's individual capacity, and not as a plaintiff or class member in any purported class or representative proceeding, and (ii) shall be resolved only in the courts of the State of Texas or the United States District Court for the Southern District of Texas and the appellate courts having jurisdiction of appeals in such courts. Any proceeding relating to this Plan or any Eligible Individual's benefits hereunder, or for the recognition and enforcement of any judgment in respect thereof (a "**Proceeding**"), to the exclusive jurisdiction of the courts of the State of Texas, the court of the United States of America for the Southern District of Texas, and appellate courts having jurisdiction of appeals from any of the foregoing, and (1) agrees that all claims in respect of any such Proceeding shall be heard and determined in such Texas State court or, to the extent permitted by law, in such federal court, (2) consents that any such Proceeding may and shall be brought in such courts and waives any objection that the Eligible Individual or the Company may now or thereafter have to the venue or jurisdiction of any such Proceeding in any such court or that such Proceeding was brought in an inconvenient court and agrees not to plead or claim the same, (3) waives all right to trial by jury in any Proceeding (whether based on contract, tort or otherwise) arising out of or relating to this Plan or the Eligible Individual's employment by the Company or any affiliate of the Company, or the Eligible Individual's or the Company's performance under, or the enforcement of, this Plan, (4) agrees that service of process in any such Proceeding may be effected by mailing a copy of such process by registered or certified mail (or any substantially similar form of mail), postage prepaid, to such party at the Eligible Individual's or the Company's address on record with the Company and (5) agrees that nothing in this Plan shall affect the right to effect service of process in any other manner permitted by the laws of the State of Texas. The parties acknowledge and agree that in connection with any dispute hereunder, the non-prevailing party shall be responsible for the payment of the prevailing party's costs and expenses, including, without limitation, the prevailing party's legal fees and expenses; provided that if the dispute solely involves a dispute as to whether "Cause", "Good Reason" or "CIC Good Reason" exists, each party shall bear its own costs and expense, regardless of the outcome of such dispute.

(k) Severability. The invalidity or unenforceability of any provision of this Plan will not affect the validity or enforceability of any other provision of this Plan, which will remain in full force and effect, and any prohibition or unenforceability in any jurisdiction will not invalidate that provision, or render it unenforceable, in any other jurisdiction.

(l) Section 409A.

(i) This Plan is intended to comply with Section 409A or an exemption thereunder, and payments shall be made under this Plan upon an event and in a manner permitted by Section 409A. This Plan shall be construed and operated accordingly. The Company may amend this Plan at any time to the extent necessary to comply with Section 409A. Any Eligible Individual shall perform any act, or refrain from performing any act, as reasonably requested by the Company to comply with any correction procedure promulgated pursuant to Section 409A. In no event shall the Company be responsible or liable for any additional tax, interest or penalty that may be imposed on an Eligible Individual by Section 409A or damages for failing to comply with Section 409A.

(ii) A termination of employment shall not be deemed to have occurred for purposes of any provision of this Plan providing for the payment of any amounts subject to Section 409A upon or following a termination of employment unless such termination is also a Separation of Service. Notwithstanding any to the contrary in this Plan, to the extent required to avoid the imposition of penalties or interest under Section 409A, any payment or benefit to be paid or provided on account of an Eligible Individual's Separation from Service to an Eligible Individual who is a "specified employee" (within the meaning of Section 409A(a)(2)(B) of the Code) that would be paid or provided prior to the first day of the seventh (7th) month following the Eligible Individual's Separation from Service shall be paid or provided on the first day of the seventh (7th) month following the Eligible Individual's Separation from Service or, if earlier, the date of the Eligible Individual's death.

(iii) Each payment to be made under this Plan shall be treated as a right to receive a series of separate payments and each such payment shall be a separately identifiable, determinable or designated amount for purposes of Section 409A.

(iv) In no event may an Eligible Individual, directly or indirectly, designate the calendar year of a payment hereunder. Notwithstanding any provision of this Plan to the contrary, in no event shall the timing of an Eligible Individual's execution of a release, directly or indirectly, result in an Eligible Individual designating the calendar year of payment of any deferred compensation subject to Section 409A, and if a payment subject to Section 409A is subject to execution of a release and could be made in more than one taxable year, payment of such an amount shall be made in the later taxable year. All reimbursements and in-kind benefits provided under the Plan shall be made or provided in accordance with the requirements of Section 409A.

(m) Clawback. Notwithstanding any provision in this Plan to the contrary, to the extent required by (i) applicable law, including, without limitation, the requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, any SEC rule or any applicable securities exchange listing standards and/or (ii) any policy that may be adopted or amended by the Board from time to time, all cash paid hereunder shall be subject to forfeiture and/or recoupment to the extent necessary to comply with such law(s) and/or policy.

(n) PHSA § 2716. Notwithstanding anything to the contrary in this Plan, in the event that the Company or any of its Affiliates is subject to the sanctions imposed pursuant to Section 2716 of the Public Health Service Act by reason of this Plan, the Company may amend this Plan at any time with the goal of giving the Eligible Individual the economic benefits described herein in a manner that does not result in such sanctions being imposed.

[Signature Page Follows]

IN WITNESS WHEREOF, the Company has adopted this Change in Control and Severance Benefit Plan as of the Effective Date.

RING ENERGY, INC.

By: /s/ Paul D. McKinney
Name: Paul D. McKinney
Title: Chief Executive Officer and Chairman of the Board

[Signature page to the Change in Control and Severance Benefit Plan]

SCHEDULE I
OFFICER TIERS

Tier	Name and Position
Tier 1	As determined by the Administrator from time to time in its sole and absolute discretion.
Tier 2	As determined by the Administrator from time to time in its sole and absolute discretion.

SCHEDULE II

TIER 3 EMPLOYEES

Tier	Name and Position
Tier 3	As determined by the Administrator or the Chief Executive Officer of the Company from time to time.

EXHIBIT A

FORM OF GENERAL RELEASE

1. The undersigned ("**Employee**"), on Employee's own behalf and on behalf of Employee's heirs, agents, representatives, attorneys, assigns, executors and/or anyone acting on Employee's behalf, and in consideration of the promises, assurances, and covenants set forth in the Ring Energy, Inc. Change In Control and Severance Benefit Plan, as in effect on of March 6, 2024 (the "**Plan**"), under which Employee is an Eligible Individual, but to which Employee is not automatically entitled, including, but not limited to, the payment of any severance thereunder, hereby fully releases Ring Energy, Inc. and its successors and affiliates (the "**Company**"), its parents, subsidiaries, officers, shareholders, partners, members, individual employees, agents, representatives, directors, managers, employees, attorneys, affiliates, successors, and anyone acting on its behalf, known or unknown, from all claims and causes of action by reason of any injuries and/or damages or losses, known or unknown, foreseen or unforeseen, patent or latent which Employee has sustained or which may be sustained as a result of any facts and circumstances arising out of or in any way related to Employee's employment by the Company or the termination of that employment, and to any other disputes, claims, disagreements, or controversies between Employee and the Company up to and including the date this Release is signed by Employee. Employee's release includes, but is not limited to, any contract benefits, claims for quantum meruit, claims for wages, bonuses, employment benefits, moving expenses, stock options, profits units, or damages of any kind whatsoever, arising out of any contracts, express or implied, any covenant of good faith and fair dealing, express or implied, any theory of unlawful discharge, torts and related damages (including, but not limited to, emotional distress, loss of consortium, and defamation) any legal restriction on the Company's right to terminate Employee's employment and/or services, or any federal, state or other governmental statute or ordinance, including, without limitation, Title VII of the Civil Rights Act of 1964 (as amended), the federal Age Discrimination in Employment Act of 1967 (29 U.S.C. § 21, et seq.) (as amended) ("**ADEA**"), the federal Americans with Disabilities Act of 1990, the Americans with Disabilities Act of 2008, the Family Medical Leave Act of 1993, the Genetic Information Nondiscrimination Act of 2008, any state laws concerning discrimination or harassment including the Fair Employment and Housing Act, as well as other state employment laws including Chapter 21 of the Texas Labor Code (Tex. Lab. Code Ann. §§ 21.001 to 21.556), the Texas Anti-Retaliation Act (Tex. Lab. Code Ann. § 451.001), the Texas Payday Law (Tex. Lab. Code Ann. §§ 61.001 to 61.095), or any other legal limitation on contractual or employment relationships, and any and all claims for any loss, cost, damage, or expense with respect to Employee's liability for taxes, penalties, interest or additions to tax on or with respect to any amount received from the Company or otherwise includible in Employee's gross income, including, but not limited to, any liability for taxes, penalties, interest or additions to tax arising from the failure of the Plan, or any other employment, severance, profit sharing, bonus, equity incentive or other compensatory plan to which Employee and the Company are or were parties, to comply with, or to be operated in compliance with the Internal Revenue Code of 1986, as amended, including, but not limited to, Section 409A thereof, or any provision of state or local income tax law; provided, however, that notwithstanding the foregoing, the release set forth in this Section shall not extend to: (a) any vested rights under any pension, retirement, profit sharing or similar plan; or (b) Employee's rights, if any, to indemnification or defense under the Company's articles of incorporation, bylaws and/or policy or procedure, any indemnification agreement with Employee or under any insurance contract, in connection with Employee's acts or omissions within the course and scope of Employee's employment with the Company (this "**Release**"). Appendix A to this Release sets forth the benefits, payments and obligations to which Employee is entitled under the Plan if, and only if, this Release is executed, delivered and become irrevocable by no later than _____________, which is sixty (60) days after the Employee's Date of Termination. Employee acknowledges and agrees that he is not entitled to any other termination or severance benefits whether under the Plan or otherwise. Capitalized terms not otherwise defined herein shall have the meanings ascribed to them in the Plan.

2. [Employee acknowledges that Employee is knowingly and voluntarily waiving and releasing any rights Employee may have under the ADEA. Employee also acknowledges that the consideration given for the waiver and release hereunder is in addition to anything of value to which Employee is already entitled. Employee further acknowledges that Employee has been advised by this writing, as required by the ADEA, that: (a) Employee's waiver and release hereunder do not apply to any rights or claims that may arise after the execution date of this Release; (b) Employee has been advised hereby that Employee has the right to consult with an attorney prior to executing this Release; (c) Employee has [twenty-one (21) days][forty-five (45) days] to consider this Release (although Employee may choose to voluntarily execute this Release earlier); (d) Employee has seven (7) days following the execution of this Release to revoke this Release; and (e) this Release will not be effective until the date upon which the revocation period has expired, which will be the eighth (8th) day after this Release is executed by Employee (the "**Effective Date**").]

3. Nothing in this Release (including, without limitation, Sections 4, 5 and 7 hereof), the Plan or any other Company agreement, policy or procedure (this Release, the Plan and such other agreements, policies and procedures, collectively, the "**Company Arrangements**") limits your ability to communicate directly with and provide information, including documents, not otherwise protected from disclosure by any applicable law or privilege to the U.S. Securities and Exchange Commission (the "**SEC**") or any other federal, state or local governmental agency or commission (each, a "**Government Agency**") regarding possible legal violations, without disclosure to the Company. The Company may not retaliate against you for any of these activities, and nothing in the Company Arrangements requires you to waive any monetary award or other payment that you might become entitled to from the SEC or any other Government Agency.

Further, nothing in the Company Arrangements precludes you from filing a charge of discrimination with the Equal Employment Opportunity Commission or a like charge or complaint with a state or local fair employment practice agency. However, once this Release becomes effective, you may not receive a monetary award or any other form of personal relief from the Company in connection with any such charge or complaint that you filed or is filed on your behalf.

Notwithstanding anything to the contrary in the Company Arrangements, as provided for in the Defend Trade Secrets Act of 2016 (18 U.S.C. § 1833(b)), you will not be held criminally or civilly liable under any federal or state trade secret law for the disclosure of a trade secret that (a) is made (i) in confidence to a federal, state, or local government official, either directly or indirectly, or to an attorney, and (ii) solely for the purpose of reporting or investigating a suspected violation of law; or (b) is made in a complaint or other document filed in a lawsuit or other proceeding, if such filing is made under seal. Without limiting the foregoing, if you file a lawsuit for retaliation by the Company for reporting a suspected violation of law, you may disclose the trade secret to your attorney and use the trade secret information in the court proceeding, if you (x) file any document containing the trade secret under seal, and (y) do not disclose the trade secret, except pursuant to court order.

4. Employee agrees that, except to the extent it conflicts with Section 3 of this Release, Section 7 and Section 9 of the Plan shall by their terms survive the execution of this Release and that the parties' rights and duties thereunder shall not in any way be affected by this Release. Employee also warrants and represents that Employee has returned any and all documents and other property of the Company constituting a trade secret or other confidential research, development or commercial information in Employee's possession, custody or control, and represents and warrants that Employee has not retained any copies or originals of any such property of the Company. Employee further warrants and represents that, except as provided by Section 3, Employee has never violated Section 9 of the Plan and will not do so in the future.

5. Employee acknowledges that because of Employee's position with the Company, Employee may possess information that may be relevant to or discoverable in connection with claims, litigation or judicial, arbitral or investigative proceedings initiated by a private party or by a regulator, governmental entity, or self-regulatory organization, that relates to or arises from matters with which Employee was involved during Employee's employment with the Company, or that concern matters of which Employee has information or knowledge (collectively, a "**Proceeding**"). Employee agrees that Employee shall testify truthfully in connection with any such Proceeding. Except as provided in Section 3, Employee agrees that Employee shall cooperate with the Company in connection with every such Proceeding, and that Employee's duty of cooperation shall include an obligation to meet with the Company representatives and/or counsel concerning all such Proceedings for such purposes, and at such times and places, as the Company reasonably requests, and to appear for deposition and/or testimony upon the Company's request and without a subpoena. The Company shall reimburse Employee for reasonable out-of-pocket expenses that Employee incurs in honoring Employee's obligation of cooperation under this Section 5 if the Employee timely submits receipts or documentation that supports the reimbursement that the Employee requests from the Company.

6. Employee and the Company understand and agree that it is in their mutual best interest to minimize the effect of Employee's separation upon the Company's business and upon Employee's professional reputation. Accordingly, Employee agrees to take all actions reasonably requested of Employee by the Company in order to accomplish that objective. To this end, Employee shall consult with the Company concerning business matters on an as-needed and as-requested basis, the Company shall exercise reasonable efforts to avoid conflicts between such consulting and Employee's personal and other business commitments, and Employee shall exercise reasonable efforts to fulfill the Company's consulting requests in a timely manner.

7. Employee covenants never to disparage or speak ill of the Company or any Company product or service, or of any past or present employee, manager, officer or director of the Company, except as provided in Section 3. This obligation to never disparage the Company, its product or service or any past or present employee, manager, officer or director of the Company, except as provided in Section 3 shall include any verbal conversation, email/text/instant messaging statements, statements made to any electronic and print media, and any web-based social media site or blog (e.g., LinkedIn, Facebook, Glassdoor.com, Instagram and/or Twitter). Employee further agrees not to harass, intimidate, bully, or behave unprofessionally towards any past, present or future Company employee, manager, officer or director.

8. **Release of Unknown Claims.** It is the intention of Employee that this Release is a general release which shall be effective as a bar to each and every claim, demand, or cause of action it releases. Employee recognizes that Employee may have some claim, demand, or cause of action against the Company of which Employee is totally unaware and unsuspecting which Employee is giving up by execution of this release. It is the intention of Employee in executing this Release that it will deprive Employee of each such claim, demand or cause of action and prevent Employee from asserting it against the released parties.

[EMPLOYEE NAME]

By: ______________________________

EXHIBIT B

FORM OF PARTICIPATION AGREEMENT

[DATE]

Dear [NAME]:

We are pleased to inform you that you are eligible to participate in the Ring Energy, Inc. Change in Control and Severance Benefit Plan (as it may be amended from time to time, the "**Plan**"). Your participation in the Plan is subject to your execution and delivery of this agreement, which constitutes a Participation Agreement, and to the terms and conditions of the Plan, which is incorporated herein and deemed to be part of this Participation Agreement for all purposes. Unless otherwise defined herein, capitalized terms used in this Participation Agreement shall have the meanings set forth in the Plan.

You are party to an employment agreement with the Company dated [ ] (the "**Former Employment Agreement**"). By signing below, you hereby terminate such Former Employment Agreement and irrevocably forfeit any right to benefits set forth therein, and you understand and agree that such Former Employment Agreement shall be of no further force or effect as of the date set forth below, and you shall be an at-will employee hereafter, as described in the Plan.

You acknowledge and agree that the Plan and this Participation Agreement supersede all prior severance benefit policies, plans, agreements and arrangements of the Company or its Affiliates (and supersede all prior oral or written communications by the Company or its Affiliates with respect to severance benefits), and all such prior policies, plans, arrangements and communications are hereby null and void and of No further force and effect, solely with respect to your severance entitlements set forth therein.

You specifically agree to the provisions of Section 7, Section 9 and Section 10 of the Plan.

This Participation Agreement may be executed in separate counterparts, each of which shall be deemed an original, but all of which taken together shall constitute one and the same instrument. Please execute this Participation Agreement in the space provided below and send a fully executed copy to the undersigned no later than [ ].

Sincerely,

RING ENERGY, INC.

By:____________________________
Name:
Title:

AGREED AND ACCEPTED

This ________ day of ____________, 20__ by:

[NAME]

Exhibit 23.1

Cawley, Gillespie & Associates, Inc.

petroleum consultants

6500 RIVER PLACE BLVD, SUITE 3-200 306 WEST SEVENTH STREET, SUITE 302 1000 LOUISIANA STREET, SUITE 1900
AUSTIN, TEXAS 78730-1111 FORT WORTH, TEXAS 76102-4987 HOUSTON, TEXAS 77002-5008
512-249-7000 817- 336-2461 713-651-9944

www.cgaus.com

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of the name Cawley, Gillespie & Associates, Inc., to the references to us and to our reserves reports for the years ended December 31, 2022 December 31, 2023, December 31, 2021 December 31, 2022, and December 31, 2020 December 31, 2021, in Ring Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2022 December 31, 2023, to references to our report dated February 3, 2023 January 26, 2024, containing our opinion on estimates of proved reserves, future production and income attributable to certain leasehold interest of Ring Energy, Inc. as of December 31, 2022 December 31, 2023 (our "Report"), and to the inclusion of our Report as an exhibit in Ring Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2022 December 31, 2023. We also consent to all such references and to the incorporation by reference of such information and our Report in Ring Energy, Inc.'s Registration Statements on Form S-3 (Nos. 333-229515, 333- 230966 333-230966 and 333-237988) and Form S-8 (Nos. 333-191485 and 333-257633). Very truly yours, CAWLEY, GILLESPIE & ASSOCIATES, INC.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

Texas Registered Engineering Firm F-693

0001628280-24-009691image_0.jpg

J. Zane Meekins, P. E.

Executive Vice President

Fort Worth, Texas March 9, 2023

March 7, 2024

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 9, 2023 March 7, 2024, with respect to the financial statements and internal control over financial reporting included in the Annual Report of Ring Energy, Inc. on Form 10-K for the year ended December 31, 2022 December 31, 2023. We consent to the incorporation by reference of said reports in the Registration Statements of Ring Energy, Inc. on Forms S-3 (File No. 333-229515, File No. 333-230966, File No. 333-237988 and File No. 333-267599) and Forms S-8 (File No. 333-191485 and File No. 333-257633).

/s/ GRANT THORNTON LLP

Houston, Texas
March 9, 2023 7, 2024

---

slide1

Exhibit 23.3 What inspires you, inspires us. | eidebailly.com 7001 E. Belleview Ave., Ste. 700 | Denver, CO 80237-2733 | TF 866.740.4100 | T 303.770.5700 | F 303.770.7581 | EOE CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM The statements of operations, stockholders' equity and cash flows for the year ended December 31, 2020 of Ring Energy, Inc. (the "financial statements"), included in Part IV of the Form 10-K for the fiscal year ended December 31, 2022, have been audited by Eide Bailly LLP, independent auditors, as stated in our report appearing herein. We consent to the inclusion in the Form 10-K for the fiscal year ended December 31, 2022 of our report, dated March 16, 2021, on our audit of the financial statements of Ring Energy, Inc. Denver, Colorado March 9, 2023

Exhibit 31.1

CERTIFICATIONS

I, Paul D. McKinney, certify that:

1. I have reviewed this annual report on Form 10-K of Ring Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of 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.

Date: March 9, 2023 7, 2024

/s/ Paul D. McKinney
Paul D. McKinney, CEO
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, Travis T. Thomas, certify that:

1. I have reviewed this annual report on Form 10-K of Ring Energy, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

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

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

c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of 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.

Date: March 9, 2023 7, 2024

/s/ Travis T. Thomas
Travis T. Thomas, CFO
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350

AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report on Form 10-K of Ring Energy, Inc. (the "Company") for the year ended December 31, 2022 December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned chief executive officer and principal executive officer of the Company, hereby certifies 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 results of operations of the Company.

Date: March 9, 2023 March 7, 2024

/s/ Paul D. McKinney
Paul D. McKinney
Chief Executive Officer
(Principal Executive Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

Exhibit 32.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350

AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report on Form 10-K of Ring Energy, Inc. (the “Company”) for the year ended December 31, 2022 December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned chief financial officer and principal financial officer of the Company, hereby certifies 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 results of operations of the Company.

Date: March 9, 2023 March 7, 2024

/s/ Travis T. Thomas
Travis T. Thomas
Chief Financial Officer
(Principal Financial Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.

sl

Exhibit 97.1

RING ENERGY, INC.

CLAWBACK POLICY

The Board of Directors (the "**Board**") of Ring Energy, Inc., a Nevada corporation (the "**Company**"), believes that it is in the best interests of the Company and its stockholders to adopt this Clawback Policy (this "**Policy**"), which provides for the recovery of certain incentive compensation in the event of an Accounting Restatement (as defined below). This Policy is designed to comply with, and shall be interpreted to be consistent with, Section 10D of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**"), Rule 10D-1 promulgated under the Exchange Act and Section 811 of the NYSE American Company Guide (the "**Listing Standards**").

1. Administration

Except as specifically set forth herein, this Policy shall be administered by the Compensation Committee of the Board (the "**Administrator**"). The Administrator is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate or advisable for the administration of this Policy. Any determinations made by the Administrator shall be final and binding on all affected individuals and need not be uniform with respect to each individual covered by this Policy. In the administration of this Policy, the Administrator is authorized and directed to consult with the full Board or such other committees of the Board, as may be necessary or appropriate as to matters within the scope of such other committee's responsibility and authority. Subject to any limitation at applicable law, the Administrator may authorize and empower any officer or employee of the Company to take any and all actions necessary or appropriate to carry out the purpose and intent of this Policy (other than with respect to any recovery under this Policy involving such officer or employee).

2. Definitions

As used in this Policy, the following definitions shall apply:

A. "**Accounting Restatement**" means an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements (a "Big R" restatement), or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (a "little r" restatement).

B. "**Administrator**" has the meaning set forth in Section 1 hereof.

C. "**Board**" has the meaning set forth in the Preamble.

D. "**Clawback Eligible Incentive Compensation**" means all Incentive-based Compensation Received by a Covered Executive (i) after beginning service as a Covered Executive, (ii) who served as a Covered Executive at any time during the applicable performance period relating to any Incentive-based Compensation (whether or not such Covered Executive is serving at the time the Erroneously Awarded Compensation is required to be repaid to the Company), (iii) while the Company has a class of securities listed on a national securities exchange or a national securities association, and (iv) during the applicable Clawback Period (as defined below).

E. "**Clawback Period**" means the three completed fiscal years immediately preceding the Restatement Date (as defined below), as well as any transition period (that results from a change in the Company's fiscal year) within or immediately following those three completed fiscal years (except that a transition period that comprises a period of at least nine months shall count as a completed fiscal year).

F. "**Code**" has the meaning set forth in Section 5 hereof.

G. "**Company**" has the meaning set forth in the Preamble.

H. "**Covered Executives**" means each individual who is currently or was previously designated as an "officer" of the Company as defined in Rule 16a-1(f) under the Exchange Act. For the avoidance of doubt, the identification of an executive officer for purposes of this Policy shall include each executive officer who is or was identified pursuant to Item 401(b) of Regulation S-K, as well as the principal financial officer and principal accounting officer (or, if there is no principal accounting officer, the controller).

I. "**Erroneously Awarded Compensation**" means, with respect to each Covered Executive in connection with an Accounting Restatement, the amount of Clawback Eligible Incentive Compensation that exceeds the amount of Incentive-based Compensation that otherwise would have been Received had it been determined based on the restated amounts, computed without regard to any taxes paid by the Covered Executive in respect of the Erroneously Awarded Compensation.

J. "**Exchange Act**" has the meaning set forth in the Preamble.

K. "**Financial Reporting Measures**" means measures that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and all other measures that are derived wholly or in part from such measures. Stock price and total shareholder return (and any

measures that are derived wholly or in part from stock price or total shareholder return) shall, for purposes of this Policy, be considered Financial Reporting Measures. For the avoidance of doubt, a Financial Reporting Measure need not be presented in the Company's financial statements or included in a filing with the SEC.

L. "**Effective Date**" has the meaning set forth in Section 9 hereof.

M. "**Incentive-based Compensation**" means any compensation that is granted, earned or vested based wholly or in part upon the attainment of a Financial Reporting Measure.

N. “**Listing Standards**” has the meaning set forth in the Preamble.

O. “**NYSE American**” means the NYSE American LLC.

P. “**Policy**” has the meaning set forth in the Preamble.

Q. “**Received**” means, with respect to any Incentive-based Compensation, actual or deemed receipt, and Incentive-based Compensation shall be deemed received in the Company’s fiscal period during which the Financial Reporting Measure specified in the Incentive-based Compensation award is attained, even if the payment or grant of the Incentive-based Compensation to the Covered Executive occurs after the end of that period.

R. “**Restatement Date**” means the earlier to occur of (i) the date the Board or a committee of the Board, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement or (ii) the date a court, regulator or other legally authorized body directs the Company to prepare an Accounting Restatement, in each case regardless of if or when the restated financial statements are filed.

S. “**SEC**” means the U.S. Securities and Exchange Commission.

3. Recovery of Erroneously Awarded Compensation in the Event of an Accounting Restatement

In the event the Company is required to prepare an Accounting Restatement, the Company shall reasonably promptly recover the amount of any Erroneously Awarded Compensation Received by any Covered Executive, as calculated pursuant to Section 4 hereof, during the Clawback Period.

---

4. Erroneously Awarded Compensation: Amount Subject to Recovery

After an Accounting Restatement, the Administrator shall determine the amount of any Erroneously Awarded Compensation Received by each Covered Executive and shall promptly notify each Covered Executive with a written notice containing the amount of any Erroneously Awarded Compensation and a demand for repayment or return of such compensation, as applicable.

For Incentive-based Compensation based on stock price or TSR: (a) the Administrator shall determine the amount of Erroneously Awarded Compensation based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or TSR upon which the Incentive-based Compensation was Received; and (b) the Company shall maintain documentation of the determination of that reasonable estimate and provide such documentation to the NYSE American.

5. Method of Recovery

The Administrator shall determine, in its sole discretion, the timing and method for reasonably promptly recovering Erroneously Awarded Compensation hereunder, which may include without limitation (a) seeking reimbursement of all or part of any cash or equity-based award, (b) cancelling prior cash or equity-based awards, whether vested or unvested or paid or unpaid, (c) cancelling or offsetting against any planned future cash or equity-based awards, (d) forfeiture of deferred compensation, subject to compliance with Section 409A of the Internal Revenue Code of 1986, as amended (the “**Code**”), and the regulations promulgated thereunder, and (e) any other method authorized by applicable law or contract. Subject to compliance with any applicable law, the Administrator may affect recovery under this Policy from any amount otherwise payable to the Covered Executive, including amounts payable to such individual under any otherwise applicable Company plan or program, including base salary, bonuses or commissions and compensation previously deferred by the Covered Executive.

To the extent that the Covered Executive has already reimbursed the Company for any Erroneously Awarded Compensation Received under any duplicative recovery obligations established by the Company or applicable law, it shall be appropriate for any such reimbursed amount to be credited to the amount of Erroneously Awarded Compensation that is subject to recovery under this Policy.

To the extent that a Covered Executive fails to repay all Erroneously Awarded Compensation to the Company when due, the Company shall take all actions reasonable and appropriate to recover such Erroneously Awarded Compensation from the applicable Covered Executive. The applicable Covered Executive shall be required to reimburse the Company for any and all expenses reasonably incurred (including legal fees) by the Company in recovering such Erroneously Awarded Compensation in accordance with the immediately preceding sentence.

The Company is authorized and directed pursuant to this Policy to recover Erroneously Awarded Compensation in compliance with this Policy unless the Administrator has determined

4

---

that recovery would be impracticable solely for the following limited reasons, and subject to the following procedural and disclosure requirements:

- The direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered. Before concluding that it would be impracticable to recover any amount of Erroneously Awarded Compensation based on expense of enforcement, the Administrator must make a reasonable attempt to recover such erroneously awarded compensation, document such reasonable attempt(s) to recover and provide that documentation to the NYSE American; or

- Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Code and regulations thereunder.

6. Disclosure Requirements

The Company shall file all disclosures with respect to this Policy required by applicable SEC filings and rules.

7. No Indemnification of Covered Executive

Notwithstanding the terms of any indemnification or insurance policy or any contractual arrangement with any Covered Executive, or any provision of the Company's articles of incorporation, bylaws or applicable law, that may be interpreted to the contrary, the Company shall not indemnify any Covered Executives against the loss of any Erroneously Awarded Compensation, including any payment or reimbursement for the cost of third-party insurance purchased by any Covered Executives to fund potential clawback obligations under this Policy.

8. Administrator Indemnification

Any members of the Administrator, and any other members of the Board who assist in the administration of this Policy, shall not be personally liable for any action, determination or interpretation made with respect to this Policy and shall be fully indemnified by the Company to the fullest extent under applicable law and Company policy with respect to any such action, determination or interpretation. The foregoing sentence shall not limit any other rights to indemnification of the members of the Board under applicable law or Company policy.

9. Effective Date; Retroactive Application

This Policy shall be effective as of October 2, 2023 (the "**Effective Date**"). The terms of this Policy shall apply to any Incentive-based Compensation that is Received by Covered Executives on or after the Effective Date, even if such Incentive-based Compensation was approved, awarded, granted or paid to Covered Executives prior to such date. Without limiting the generality of Section 5 hereof, and subject to applicable law, the Administrator may effect recovery under this Policy from any amount of compensation approved, awarded, granted, payable or paid to the Covered Executive prior to, on or after the Effective Date.

5

---

10. Amendment; Termination

The Board may amend, modify, supplement, rescind or replace all or any portion of this Policy at any time and from time to time in its discretion, and shall amend this Policy as it deems necessary to comply with applicable law or any rules or standards adopted by a national securities exchange on which the Company's securities are listed.

11. Other Recovery Rights; Company Claims

The Committee intends that this Policy will be applied to the fullest extent required by applicable law. Any employment agreement, equity award agreement, compensatory plan or any other agreement or arrangement with a Covered Executive shall be deemed to include, as a condition to the grant of any benefit thereunder, an agreement by the Covered Executive to abide by the terms of this Policy. Any right of recovery under this Policy is in addition to, and not in lieu of, any other remedies or rights of recovery that may be available to the Company under applicable law, regulation or rule or pursuant to the terms of any policy of the Company or any provision in any employment agreement, equity award agreement, compensatory plan, agreement or other arrangement.

12. Successors

This Policy shall be binding and enforceable against all Covered Executives and, to the extent required by applicable law or guidance from the SEC or NYSE American, their beneficiaries, heirs, executors, administrators or other legal representatives.

Clawback Policy Acknowledgment

I, the undersigned, agree and acknowledge that I am fully bound by, and subject to, all of the terms and conditions of the Ring Energy, Inc. Clawback Policy (as may be amended, restated, supplemented or otherwise modified from time to time, the "**Policy**"). In the event of any inconsistency between the Policy and the terms of any employment agreement to which I am a party, or the terms of any compensation plan, program or agreement under which any compensation has been granted, awarded, earned or paid, the terms of the Policy shall govern. In the event it is determined by the Administrator that any amounts granted, awarded, earned or paid to me must be forfeited or reimbursed to the Company, I will promptly take any action necessary to effectuate such forfeiture and/or reimbursement. Any capitalized terms used in this Acknowledgment without definition shall have the meaning set forth in the Policy.

Signature: ________________________

Printed Name: _____________________

Date: ____________________________

Exhibit 99.1 February 3, 2023

0001628280-24-009691image_1a.jpg

January 26, 2024

Mr. Alex Dyes
Executive Vice President of Engineering & Corporate Strategy
Ring Energy, Inc.
1725 Hughes Landing Blvd., Suite 900

The Woodlands, TX 77380

Re: Evaluation Summary

Ring Energy, Inc. Interests

Proved Reserves

Texas and New Mexico

As of January 1, 2023 December 31, 2023

Dear Mr. Dyes:

As requested, we are submitting our estimates of proved reserves and our forecasts of the resulting economics attributable to the above captioned interests as of January 1, 2023December 31, 2023. It is our understanding that the proved reserve estimates shown herein constitute 100 percent of all proved reserves owned by Ring Energy, Inc. ("Ring Energy"). This report, completed on February 3, 2023January 26, 2024, has been prepared for use in filings with the Securities and Exchange Commission ("SEC") by Ring Energy. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserves estimates and economic forecasts for the proved reserves are summarized below: Proved Proved Developed Developed Non- Proved Total Producing Producing Undeveloped Proved Net Reserves Oil/Condensate -- Mbbl 48,274.8 8,737.3 31,692.6 88,704.7 Gas -- MMcf 72,295.8 34,103.3 51,471.4 157,870.5 NGL -- Mbbl 10,673.6 4,659.2 7,772.9 23,105.7 Revenue Oil/Condensate -- M$ 4,639,803.5 838,643.9 3,044,362.3 8,522,809.0 Gas -- M$ 304,763.7 153,528.3 222,115.6 680,407.6 NGL -- M$ 315,837.6 130,209.9 222,694.8 668,742.2 Severance and Ad Valorem Taxes -- M$ 345,146.7 74,016.2 226,159.7 645,322.6 Operating Expenses -- M$ 1,191,150.4 360,100.6 555,321.1 2,106,572.0 Investments -- M$ 67,412.9 117,240.0 462,543.8 647,196.8 Operating Income (BFIT) -- M$ 3,656,695.5 571,025.4 2,245,148.3 6,472,867.5 Discounted @ 10% -- M$ 1,669,008.1 237,674.3 866,974.6 2,773,656.5

		Proved Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved
Net Reserves					
Oil/Condensate	-- Mbbl	48,767.9	7,261.1	26,112.2	82,141.3
Gas	-- MMcf	69,101.8	30,794.2	46,500.3	146,396.3
NGL	-- Mbbl	10,893.3	4,556.7	7,768.7	23,218.6
Revenue					
Oil/Condensate	-- M$	3,705,334.3	551,310.3	1,982,320.1	6,238,964.7
Gas	-- M$	26,632.5	18,906.8	24,992.3	70,531.6
NGL	-- M$	153,301.0	58,168.0	101,444.8	312,913.8
Severance and Ad Valorem Taxes	-- M$	243,490.0	39,275.6	131,170.1	413,935.7
Operating Expenses	-- M$	1,197,303.4	255,759.5	546,304.5	1,999,367.3
Investments	-- M$	61,798.7	83,786.9	416,477.8	562,063.4
Operating Income (BFIT)	-- M$	2,382,675.5	249,563.0	1,014,804.5	3,647,043.6
Discounted @ 10%	-- M$	**1,151,093.9**	**111,585.0**	**384,352.7**	**1,647,031.4**

The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

slide2

As requested, hydrocarbon pricing of $6.358 $2.637 per MMBtu of gas (Henry Hub spot) and $90.15 $74.70 per barrel of oil/condensate (WTI posted) was applied without escalation. In accordance with the Securities and Exchange Commission guidelines, these prices were determined as an unweighted arithmetic average of the first-day-of- the-month first-day-of-the-month price for the previous 12 months. As directed, this 12-month period ends in December 2022. 2023. The oil and gas prices were held constant and were adjusted for gravity, heating value, quality, transportation and marketing. The adjusted volume-weighted average product prices over the life of the properties are $96.08 $75.95 per barrel of oil, and $4.31 $0.48 per Mcf of gas. gas, and $13.48 per barrel of NGL.

Operating costs were based on operating expense records of Ring Energy. Drilling and completion costs were based on estimates provided by Ring Energy and reviewed by Cawley, Gillespie & Associates. Severance tax and ad valorem rates were specified by state/county based on actual rates. As per the Securities and Exchange Commission guidelines, neither expenses nor investments were escalated. The costs to plug and abandon all wells have been considered. For the PDP and PDNP reserves, a net cost of $48,152,062 is $47,010,056 modelled in sixteen eighteen cases scheduled over the next 50 years. The PUD cases have an average gross cost of $44,000 scheduled at the economic limit for each well.

The proved reserves classifications conform to criteria of the SEC as defined in pages 2-3 of the Appendix. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the date of this report as noted herein. In evaluating the information at our disposal concerning this report, we have excluded from our consideration all matters as to which the controlling interpretation may be legal or accounting, rather than engineering and geoscience. Therefore, the possible effects of changes in legislation or other Federal or State restrictive actions have not been considered. An on-site field inspection of the properties has not been performed. The mechanical operation or conditions of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

The reserves were estimated using a combination of the production performance, volumetric and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserves estimates were based on interpretations of factual data furnished by Ring Energy. Ownership interests were supplied by Ring Energy and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 60 years. This evaluation was supervised by J. Zane Meekins, Executive Vice President at Cawley, Gillespie & Associates, Inc. and a Registered Professional Engineer in the State of Texas (License No. 71055). Cawley, Gillespie & Associates, Inc. is independent with respect to Ring Energy as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future production rates for the subject properties.

---

slide3

Evaluation Summary Ring Energy, Inc. February 3, 2023 Page 3 Our work-papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Evaluation Summary
Ring Energy, Inc.
January 26, 2024
Page 3

0001628280-24-009691image_2a.jpg

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

slide4

APPENDIX Appendix Page 1 Cawley, Gillespie & Associates, Inc.

APPENDIX

Methods Employed in the Estimation of Reserves

0001628280-24-009691image_4.jpg 0001628280-24-009691image_5.jpg

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric*and (4) analogy.*analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance.performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance.balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available. Volumetric.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated. Analogy.

Analogy. This method, which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is a common approach used for “resource plays,” where an abundance of wells with similar production profiles facilitates the reliable estimation of future reserves with a relatively high degree of accuracy. The analogy method may also be applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained in this manner are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

slide5

APPENDIX

Reserve Definitions and Classifications

0001628280-24-009691image_4.jpg 0001628280-24-009691image_5.jpg

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves: "(22)

"(22) **Proved oil and gas reserves. 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)

"(i) The area of a 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)

"(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)

"(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)

"(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)

"(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. "(6) Developed

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

"(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)

"(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. "(31) Undeveloped

"(31) **Undeveloped oil and gas reserves. reserves**. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. "(i)

"(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)

"(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)

"(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.

slide6

APPENDIX Appendix Page 2 Cawley, Gillespie & Associates, Inc.

Appendix
Page 1 *Cawley, Gillespie & Associates, Inc.*

Appendix Page 3 Cawley, Gillespie & Associates, Inc. "(18)

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

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

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. "(iii)

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves. "(iv)

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below). reserves. "(17)

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

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. "(ii)

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project. "(iii)

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves. "(iv)

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects. "(v)

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir. "(vi)

"(vi) Pursuant to paragraph (22)(iii) of this section (above), where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations."

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that "a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K." This is relevant in that Instruction 2 to paragraph (a)(2) states: "The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item." "(26) Reserves.

"(26) **Reserves**. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project. "Note

"Note to paragraph (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)."

DISCLAIMER

THE INFORMATION CONTAINED IN THE REFINITIV CORPORATE DISCLOSURES DELTA REPORT™ IS A COMPARISON OF TWO FINANCIALS PERIODIC REPORTS. THERE MAY BE MATERIAL ERRORS, OMISSIONS, OR INACCURACIES IN THE REPORT INCLUDING THE TEXT AND THE COMPARISON DATA AND TABLES. IN NO WAY DOES REFINITIV OR THE APPLICABLE COMPANY ASSUME ANY RESPONSIBILITY FOR ANY INVESTMENT OR OTHER DECISIONS MADE BASED UPON THE INFORMATION PROVIDED IN THIS REPORT. USERS ARE ADVISED TO REVIEW THE APPLICABLE COMPANY'S ACTUAL SEC FILINGS BEFORE MAKING ANY INVESTMENT OR OTHER DECISIONS.

REFINITIV