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, 2025

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	x
Emerging growth company	o			

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

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, 2025, 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 $0.79 per share, was $155,602,776.

As of March 4, 2026, the registrant had outstanding 209,395,110 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 2026, 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.

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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,” 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 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;
- unanticipated reductions in the borrowing base under our credit agreement;
- 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;
- 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 reliable transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;
- future 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;
- 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;
- 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;
- 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 liquids or ***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.

SWD well **–** Salt water disposal well.

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 engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas. Our drilling operations target the oil and liquids rich producing formations in the Northwest Shelf and the Central Basin Platform, in the Permian Basin in Texas.

As of December 31, 2025, our leasehold acreage positions totaled 111,714 gross (96,234 net) acres and we held interests in 919 gross (758 net) producing wells. Proved reserves as of December 31, 2025 (based upon the report of our independent petroleum engineer of that date) were approximately 153.3 million Boe, of which we are the operator of approximately 99%. All of our properties are located in the Permian Basin and our proved reserves are oil-weighted, with approximately 59% consisting of oil, 19% consisting of natural gas, and 22% consisting of NGLs. Approximately 68% of the reserves are classified as PD and 32% are classified as PUD. Within the PD reserve category, 238 recompletion and re-activation opportunities are classified as PDNP and within the PUD reserve category, we have a total of 247 proved locations (38% horizontal and 62% vertical) based on the reserve report as of December 31, 2025. We believe our core leasehold in the Northwest Shelf and Central Basin Platform contain additional potential drilling locations.

2025 Highlights and Major Developments

- Closed the Lime Rock Acquisition on March 31, 2025.
- Achieved record full year production of 20,253 Boepd (65% oil), a year-over-year increase in total Boe of 3%.
- Lowered lifting costs to $10.73 per Boe, or 1% year over year including 9 months of the LRR acquisition assets.
- Responded to lower commodity price environment by pulling back on capital expenditures, executing a phased drilling program in 2025 that included drilling 18 gross, 17 net operated wells consisting of 12 horizontal and six vertical wells (gross).
- Total proved reserves were 153.3 MMBoe at year-end 2025, which increased 19.1 MMBoe, or 14% from year-end 2024. Total proved developed reserves were 103.8 MMBoe at year-end 2025, which increased 11.2 MMBoe, or 12% from year-end 2024.
- Maintained our revolving credit facility borrowing base of $585 million.

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 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 with 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 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, applying advanced technologies, and continuously seeking 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 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 we seek to balance our production and reserve growth 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 focus on delivering competitive debt-adjusted per share returns. This objective is key to delivering competitive returns to our shareholders on a sustainable basis.

Primary Business Operations

We seek to rigorously manage our asset portfolio to optimize shareholder value over the long term. Refer to Item 7 - Management’s Discussion and Analysis of Financial Condition and Results of Operations, Drilling and Completion, for details of our 2025 operations.

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. In addition, those companies may be able to pay more for producing 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 third-party pipelines that 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 flowlines 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. Our produced saltwater is generally moved by pipeline connected to our operated saltwater disposal wells or by truck 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, 2025, sales to three customers represented 89% of our oil, natural gas, and NGL revenues. As of December 31, 2025, accounts receivable from these three customers represented 82% of our total accounts receivable. Refer to the table below for the details of these percentages, respectively. We believe that the loss of any of these purchasers would not materially impact our business because we could readily find other purchasers for our oil and natural gas.

Customer:	For the year ended December 31, 2025 Percentage of Oil, Natural Gas, and Natural Gas Liquids Revenues	As of December 31, 2025 Percentage of accounts receivables from the sale of our Oil, Natural Gas and NGL production
Phillips 66 Company ("Phillips")	67%	66%
Concord Energy LLC ("Concord")	13%	10%
NGL Crude Partners ("NGL Crude")	9%	6%
Total of top three customers	89%	82%

Delivery Commitments

As of December 31, 2025, 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 expenditure needs.

Governmental Regulations

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements of 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, affects 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. These statutes and regulations require permits for drilling operations, drilling bonds, and reports concerning operations. Until recently, the trend in oil and natural gas regulation was 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.

Currently, all of our operated properties are in Texas, which 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, Texas imposes a production or severance tax with respect to the production and sale of oil, natural gas, and NGLs within 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, natural gas, and NGLs are not currently regulated and are made at negotiated 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 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, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. 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 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 FERC's actions have achieved 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 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 Texas 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 numerous 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, 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 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 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.

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 November 2021, the EPA issued a proposed rule under the CAA's New Source Performance Standards, known as Subpart OOOOa, intended to reduce methane emissions from new and existing oil and gas sources. The proposed rule sought to make the existing regulations in Subpart OOOOa more stringent and create a Subpart OOOOb to expand reduction requirements for new, modified, and reconstructed oil and gas sources, including standards focusing on certain source types that have never been regulated under the CAA (including intermittent vent pneumatic controllers, associated gas, and liquids unloading facilities). In addition, the proposed rule sought to establish "Emissions Guidelines," creating a Subpart OOOOc that would require states to 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 proposed rule supplementing the November 2021 proposed rule. Among other things, the November 2022 supplemental proposed rule sought to remove an emissions monitoring exemption for small wellhead-only sites and creates a new third-party monitoring program to flag large emissions events, referred to in the proposed rule as "super emitters." In December 2023, the 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 final rule gave states until March 2026 to develop and submit their plans for reducing methane emissions from existing sources. However, in March 2025, the EPA announced its intention to reconsider the March 2024 rule, including Subparts OOOOb and OOOOc, with a final rule expected in or around July 2026. A subsequent rule, finalized on November 26, 2025, gives states, along with federal tribes that wish to regulate existing sources, until January 2027 to develop and submit their plans for reducing methane emissions from existing sources. As a result of these regulatory changes, the scope of any final air emissions regulations or the costs for complying with such regulations are uncertain. We may incur costs as necessary to remain in compliance with these regulations. Obtaining or renewing permits also has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies can impose administrative, civil and criminal penalties and seek injunctive relief for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations.

In August 2022, the Inflation Reduction Act of 2022 ("IRA") was signed into law, which amended the CAA to establish the first ever federal fee on excess methane emissions from sources required to report their GHG emissions to the EPA, including certain oil and gas operations. In November 2024, the EPA issued a final rule implementing the methane emissions charge, although in February 2025, Congress repealed the rule under the Congressional Review Act. Additionally, under the One Big Beautiful Bill Act, enacted in July 2025 ("OBBBA"), Congress delayed the implementation of the methane emissions fee until 2034.

Additionally, in March 2025, the EPA announced formal reconsideration of the 2009 "Endangerment Finding", a declaration that various greenhouse gases endanger public health and welfare and the basis for the majority of the EPA's GHG-related regulations. In February 2026, the current administration finalized a rule repealing the Endangerment Finding. It is uncertain at this time what impact the repeal of the Endangerment Finding will have on such regulations.

Oil Pollution Prevention

The OPA amends and augments the oil spill provisions of the CWA and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening WOTUS or adjoining shorelines. 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. 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. 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 January 2023, the EPA and the Corps issued a final rule that revised the definition of WOTUS. 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 v. EPA*. However, litigation opposing the September 2023 final rule remains ongoing and substantial uncertainty exists with respect to future implementation of the September 2023 rule and the scope of CWA jurisdiction more generally. Following legal actions, implementation of the most recent rule is currently split across the country. The rule is subject to an injunction in 27 states, including Texas, resulting in implementation of the pre-2015 rule adjusted to take into account jurisdictional limitations decided by the Supreme Court in *Sackett v. EPA*. The other 23 states are subject to the WOTUS-defining rule published in September 2023. The Corps is currently pursuing a new post-*Sackett* rulemaking, the ultimate consequence of which cannot be predicted at this time. As such, uncertainty remains with respect to future implementation of the rule and the outcome of the pending litigation. Many of our customers and service providers rely on permits obtained under the CWA for their oil and gas pipeline projects, the most common of which is Nationwide Permit 12 ("NWP 12"), which, from time to time, is renewed or modified by the Corps, whose actions in turn may be subject to litigation. NWP 12 is expected to be reissued by the Corps in 2026. To the extent any action expands the scope of the CWA in areas where we or our suppliers, customers or service providers operate or imposes new or enhanced permitting requirements, our operations could be adversely impacted by increased compliance costs and energy infrastructure project delays or cancellations.

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 have been 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 Texas, the 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 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. 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 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.

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, 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. 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. The RRC adopted rules that 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 December 2024, the RRC adopted a significant overhaul of its rules regulating oil and natural gas waste management facilities in Texas. The new rules went into effect on July 1, 2025. The new rules cover waste from oil and natural gas operations, such as rock and other material pulled up from the ground during drilling, as well as waste from other operations. The rules impose requirements related to waste management practices and production methods, such as recycling produced water. The rules also update requirements on the design, construction, operation, monitoring, and closure of waste management units

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. The EPA has adopted and implemented regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration (“PSD”) pre-construction permits, and Title V operating permits for GHG emissions from certain large stationary sources that already are major sources of criteria pollutants under the CAA. Under these regulations, facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards for their GHG emissions established by the states or, in some cases, by the EPA, for those emissions. If we are required to meet "best available control technology," our operations could be adversely affected and our ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds could be restricted or delayed. 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. Although the EPA has proposed to delay GHG reporting for the oil and natural gas sector until 2034, and to otherwise repeal GHG reporting requirements for other sectors, we cannot predict whether these efforts will ultimately be successful or that GHG reporting will not be required again in the future.

The BLM has also, from time to time, considered or adopted rules regulating GHG emissions from oil and natural gas operations on federal lands. Nevertheless, there continues to be uncertainty surrounding the federal regulation of methane and other GHG emissions. Federal policy towards GHG emissions, and regulation thereunder, has varied significantly between the past several Presidential administrations. The current administration has expressed a policy preference of limiting or rescinding regulations concerning GHG emissions and promulgated a final rule, in February 2026, repealing the EPA's 2009 "Endangerment Finding" that forms the basis for most of the EPA's GHG-related rules. However, whether or how such policies and the EPA's rescission of its "Endangerment Finding" will be implemented and if they will survive any potential legal challenges, or whether future administrations or Congress may pursue new GHG emissions regulations, cannot be predicted at this time. 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.

While Congress has, from time to time, considered legislation to reduce emissions of GHGs, including proposals adopting cap-and-trade programs, carbon taxes, climate-related mitigation funds, and regulations that directly limit GHG emissions from select sources, no significant legislation has been adopted at the federal level. While Congress previously enacted the Inflation Reduction Act of 2022 (the "IRA") to advance climate-related objectives and provide financial support for alternative or lower GHG-emitting energy production, many of these incentives were repealed or otherwise modified following the change in Presidential administrations and the enactment of OBBBA. However, any similar or future climate-related legislation and accompanying policy initiatives could increase operating costs within the oil and gas industry or accelerate a transition away from fossil fuels, which could in turn reduce demand for our products and adversely affect our business and results of operations.

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. State, regional and local governments may also elect to continue to participate in international climate change initiatives, despite the current administration finalizing the United States' withdrawal from such initiatives in 2026. The participation in, or support for, climate-related policies and initiatives by politicians, regulators, financial institutions, consumers, and other stakeholders could increase opposition against, reduce funding for or lead to new limitations on, fossil fuel exploration and production activities. The full impact of these actions remains uncertain at this time; however, 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.

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. 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. Although it appears unlikely in the near term, 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.

Threatened and Endangered Species

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 CWA. 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 dunes sagebrush lizard is one example of a species that was recently listed as an endangered species. The State of Texas has filed suit challenging the listing. The dunes sagebrush lizard is found in portions of Texas, including areas where we operate. The listing of the dunes sagebrush lizard as an endangered species, may impact our operations in any area that is designated as the dunes sagebrush lizard's habitat. Depending on the locations of our operations, we may be required to comply with expensive mitigation measures intended to protect the dunes sagebrush lizard and its 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. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause increased costs arising from species protection measures or could result in limitations on development activities that could have an adverse impact on the ability to develop and produce reserves within our 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, 2025, we had 111 full-time employees. Our employees are extremely valuable to the success of the Company, and we encourage their collaboration and respect their points of view and opinions. In addition to our full-time employees, the Company also employs 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.

We recognize that attracting, retaining and developing our employees is critical for our future success. Our Senior Vice President General Counsel 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 the following.

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 a 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 accidents. 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.

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

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 Annual Report under “Forward-Looking Statements” and other information included and incorporated by reference into this Annual 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 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 horizontal wells include, but are not limited to, the following:

- the ability to fracture or stimulate the planned number of stages in a horizontal wellbore;
- the ability to run tools and other equipment the entire length of a wellbore during completion operations; and
- the ability to successfully clean out 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 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. 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 may 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 a substantial majority of our properties were categorized as proved developed.

Because a substantial percentage of our proved properties are proved undeveloped (approximately 32%), we will require significant additional capital to develop these 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 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, we have entered into crude oil and natural gas price hedging arrangements with respect to a significant portion of our expected production. Additionally, our credit facility requires us to hedge a significant portion of our production. These derivative contracts typically limit the benefit we would otherwise receive from increases in the prices for oil and natural gas.

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 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 in the winter, and hurricanes and thunderstorms in the summer), 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 loss of key members of management or failure to attract and retain other highly qualified personnel could affect the Company's business results.

Our success depends on our ability to attract, retain and motivate a highly-skilled management team and workforce. Failure to ensure that we have the depth and breadth of management and personnel with the necessary skill sets and experience could impede our ability to achieve growth objectives and execute our operational strategy. As we continue to expand, 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 inflationary pressures, it may be difficult to attract or retain these 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 and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil and natural gas production heavily 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 and we expect these markets will continue to be 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 oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing 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, 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, 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.

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 may be 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 uncertainties 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 incur write-downs of the financial carrying values of our oil and natural gas properties which could negatively impact the price 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. The cumulative effect of 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 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 year ended December 31, 2025, we recorded a non-cash write down of $108.8 million. During the years ended 2024 and 2023 we did not incur any write-downs. 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 on our financial statements.

It is difficult to estimate with any degree of 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 price 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 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 will likely 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 certain properties. All of these factors would have a negative impact on earnings and net income, and most likely the 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 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;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing 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. We may elect to not 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, 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 producing profitably.

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 oil and gas 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 properties or in our marketing of production, then our financial condition and operation results would 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 our producing properties 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. For example, for the year ended December 31, 2025, we experienced a negative price of $1.33 per Mcf of natural gas with negative net sales of approximately $9.3 million, adversely affecting our cash flows and net income.

Currently, some of our production is sold to marketers and other purchasers that have access to pipeline facilities. Much of our production is in areas with limited or no access to pipelines, thereby necessitating delivery by 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 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 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 the pad. As a result, multi-well pad drilling can cause delays in the scheduled commencement of production or interruptions to 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 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. For example, we had production stoppages in 2023, 2024, and 2025 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. Waste water from our operations typically is disposed of via underground injection. Some studies have linked 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, ground water, or produced 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, and local 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. 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 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; restrict the types, quantities, and concentration of substances that can be released into the environment in connection with drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected 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; incurrence of investigatory or remedial obligations; or the imposition of injunctive relief. Changes in environmental laws and regulations and the interpretation thereof occur from time to time, 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, 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 any 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, though recently passed laws such as the IRA advance numerous climate-related objectives. The IRA contains hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, clean fuels, electric vehicles, and supporting infrastructure and carbon capture and sequestration, among other provisions. The OBBBA rescinds or eliminates funding for multiple programs under the IRA aimed at reducing or monitoring GHG emissions and other air pollutants, such as the Greenhouse Gas Reduction Fund and methane monitoring initiatives. While the OBBBA will potentially affect federal efforts to address climate change and emissions reductions, various federal agencies have, from time to time, adopted climate change considerations into their rulemaking and decision-making processes and have promulgated regulations that seek to restrict, monitor, or otherwise limit GHG emissions. International climate commitments made by political, industrial, and financial and other stakeholders may also impact commercial, regulatory, and consumer trends related to climate change.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the CAA that, among other things, require PSD preconstruction and Title V operating permits for GHG emissions from certain large stationary sources, mandate monitoring and annual reporting of GHG emissions, and impose new standards for reducing methane emissions from oil and gas operations by limiting venting and flaring and implementing leak detection and repair programs. Federal policy towards GHG emissions, and regulation thereunder, has varied significantly between the past several Presidential administrations. The current administration has expressed a policy preference of limiting or rescinding regulations concerning GHG emissions and, in February 2026, promulgated a final rule repealing the EPA's 2009 "Endangerment Finding" and its motor vehicle GHG emission performance standards. This rescission of the "Endangerment Finding" eliminates the basis for EPA's authority under the CAA for most of its regulations concerning GHGs. However, whether or how such policies and the EPA's rescission of its "Endangerment Finding" will be implemented and if they will survive any potential legal challenges, or whether future administrations or Congress may pursue new GHG emissions regulation, cannot be predicted at this time.

At the international level, the United Nations-sponsored Paris Agreement encourages nations to limit their GHG emissions through nationally-determined, though non-binding, reduction goals. Recent Conferences of the Parties have resulted in reaffirmations of the objectives of the Paris Agreement, calls for parties to eliminate certain fossil fuel subsidies and pursue reductions in non-carbon dioxide GHG emissions, agreements to transition away from fossil fuels in energy systems and increase renewable energy capacity, financial commitments to fund energy transition efforts in developing countries, and similar initiatives, though none legally binding. However, in January 2025, the current administration ordered the revocation of any United States financial commitments on emission goals associated with international climate agreements. Then, in January 2026, the United States finalized its withdrawal from the Paris Agreement. The impacts of the United States' withdrawal and other existing or future climate-related orders, pledges, agreements or any legislation or regulation promulgated in connection with the Paris Agreement, the Global Methane Pledge, or other international conventions cannot be predicted at this time. Further, state and local governments, financial institutions, and industry groups may elect to continue participating in international climate-related initiatives.

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 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. 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 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 applicable to oil and natural gas exploration and development companies. It is unclear whether any such 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 such legislation or other 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 operating results and cash flows.

In addition, 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. Under the CAMT, a 15 percent minimum tax will be imposed on certain adjusted financial statement income of "applicable corporations," which 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. 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. The U.S. Department of the Treasury and the Internal Revenue Service have released proposed regulations and other interpretive guidance relating to the CAMT. Any significant variance from 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 the property of others held by us that has been unclaimed for a specified period. We are subject to 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.

Risks Relating to Our Capital Structure

We have significant indebtedness.

We have a Credit Facility in place with $585 million in commitments from borrowings and letters of credit under our Third Amended and Restated Credit Agreement dated June 18, 2025 with Bank of America, N.A. as Administrative Agent (the "Credit Agreement"). As of December 31, 2025, $420 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 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 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 2025, 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 2026, 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 cybersecurity attacks or breaches could result in information theft, data corruption, disruption in operations, and/or financial loss.

The oil and natural gas industry is highly 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 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. In addition, weaknesses in the cybersecurity of our vendors, suppliers, and other business partners could facilitate an attack on our technologies, systems, and networks. 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 vulnerabilities to cyberattacks. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may result in increased capital and operating costs. A cyberattack or security breach could result in liability under data privacy laws, regulatory penalties, damage to our reputation, or loss of confidence in us, or additional costs for remediation and modification or enhancement of our information systems to prevent future occurrences, all of which could have a material and adverse effect on our business, financial condition, or results of operations. While we maintain insurance that covers certain cybersecurity incidents, we may not be insured for, or our insurance may be insufficient to protect us against, particular types of cybersecurity risks, and, in the future, such insurance may not continue to be available to us on reasonable terms, if at all. To date we have not experienced any material losses relating to cyber-attacks; however, there can be no assurance that we will not suffer such losses in the future. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition, and results of operations.

Risks Relating to Our Common Stock

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

The stock markets have experienced 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 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 Directors' 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 Director of Information Technologies and Cybersecurity (“IT Director”) 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 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, Interim CFO, Chief Operations Officer, Senior Vice President General Counsel, and our Director of IT.

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

Our Director of IT is responsible for assessing and managing risks from cybersecurity threats, guiding our overall cybersecurity risk management program, and supervising both our internal cybersecurity personnel and our retained external cybersecurity consultants. Our Director of IT is responsible for reporting material incidents to our MC Committee. Our Director of IT 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 17 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 Director of IT 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 Director of IT 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 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, 2025, we owned interests in a total of 97,085 gross (83,550 net) developed acres and operate the vast majority of our acreage position. In addition, as of December 31, 2025, we owned interests in approximately 14,629 gross (12,684 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 33 proved undeveloped locations (100% horizontal) and 2 PDNP opportunities based on the reserve report as of December 31, 2025. Our reserve estimates account for the capital costs required to develop these wells and the future plugging and abandonment costs. We believe the Northwest Shelf leases contain additional potential drilling locations.

Within the Central Basin Platform, we had a total of 214 proved undeveloped locations (29% horizontal and 71% vertical) and 236 PDNP opportunities based on the reserve report as of December 31, 2025. Our reserve estimates account for the capital costs required to develop these wells and the future plugging and abandonment costs. 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 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, 2025, we owned interests in a total of 12,892 gross (8,833 net) developed acres and 8,370 gross (8,318 net) undeveloped acres with an average proved operated working interest of 92% and net revenue interest of 69%. As of December 31, 2025, the Company had interests in approximately seven gross vertical and 136 gross horizontal producing wells, of which we operate seven vertical and 120 horizontal wells. The horizontal wells predominately produce from the San Andres conventional reservoir and the vertical wells produce from the Wolfcamp reservoir.

Central Basin Platform – Andrews, Gaines, Crane, Ector, Winkler, and Ward Counties, Texas – In 2011, we acquired a 100% working interest and a 75% net revenue interest in our initial leases in Andrews County. 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, 2025, we owned interests in a total of 84,193 gross (74,717 net) developed acres and 6,259 gross (4,366 net) undeveloped acres with an average proved operated working interest of 96% and net revenue interest of 81% in the area. As of December 31, 2025, the Company had interests in approximately 509 gross vertical and 267 gross horizontal producing wells, of which we operate 401 vertical and 265 horizontal wells. The horizontal wells predominately produce from the San Andres conventional reservoir and the vertical wells produce from a variety of conventional pay zones including the 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 materially interfere with our use of these properties.

Summary of Oil and Natural Gas Reserves

As of December 31, 2025, our estimated proved reserves had a pre-tax PV-10 value (present value discounted at 10%) of approximately $1,318.2 million and a Standardized Measure of Discounted Future Net Cash Flows of approximately $1,123.5 million, over 99.8% of which relates to our properties in the Permian Basin in Texas. We spent approximately $335.8 million on acquisitions and capital projects during 2025 and 2024. 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, 2025.

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
90,320,048	176,180,576	33,594,344	153,277,821	$ 1,318,208,128	$ 1,123,493,332

[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 Annual 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:

Present value of estimated future net revenues (PV-10)	$	1,318,208,128
Future income taxes, discounted at 10%	$	194,714,796
Standardized measure of discounted future net cash flows	$	1,123,493,332

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)	Boe[1]
Balance, December 31, 2022	88,704,743	157,870,449	23,105,658	138,122,143
Purchase of minerals in place	6,543,640	3,372,965	1,089,382	8,195,183
Extensions, discoveries and improved recovery	3,098,845	4,113,480	1,014,343	4,798,768
Sales of minerals in place	(4,897,921)	(2,674,955)	(392,953)	(5,736,700)
Production	(4,579,942)	(6,339,158)	(976,852)	(6,613,320)
Revisions of previous quantity estimates [2]	(6,728,088)	(9,946,459)	(621,014)	(9,006,845)
Balance, December 31, 2023	82,141,277	146,396,322	23,218,564	129,759,229
Purchase of minerals in place	—	—	—	—
Extensions, discoveries and improved recovery	11,495,236	10,630,769	2,738,451	16,005,482
Sales of minerals in place	(1,140,568)	(56,020)	(16,361)	(1,166,266)
Production	(4,861,628)	(6,423,674)	(1,258,814)	(7,191,054)
Revisions of previous quantity estimates [2]	(6,730,246)	(730,235)	3,621,245	(3,230,707)
Balance, December 31, 2024	80,904,071	149,817,162	28,303,085	134,176,684
Purchase of minerals in place	9,915,483	10,067,543	2,373,336	13,966,743
Extensions, discoveries and improved recovery	7,281,553	10,624,783	2,133,786	11,186,136
Sales of minerals in place	—	—	—	—
Production	(4,841,164)	(6,980,958)	(1,387,818)	(7,392,476)
Revisions of previous quantity estimates [2]	(2,939,895)	12,652,046	2,171,955	1,340,734
Balance, December 31, 2025	90,320,048	176,180,576	33,594,344	153,277,821

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

(2) Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history, a rule that undeveloped reserves must be drilled within five years of originally being booked, and/or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

Notable changes in proved reserves for the year ended December 31, 2025 included the following:

- *Extensions.* In 2025, extensions of 11.2 MMBoe were primarily the result of 41 newly added PUDs in addition to an active leasing program. Also impacting extensions were three successfully drilled wells in the Northwest Shelf and Central Basin Platform.

- *Purchase of minerals in place.* In 2025, the Company completed the acquisition of Lime Rock oil and gas leases and related property within Andrews County, as well as a few other minor acquisitions, that resulted in 14.0 MMBoe of additional reserves.

- *Sales of minerals in place.* In 2025, the Company did not sell any reserves.

- *Revision of previous quantity estimates.* In 2025, the positive revisions of prior reserves of 1.3 MMBoe consisted of a positive 7.2 MMBoe related to changes in performance and other economic factors, offset by a negative 5.9 MMBoe related to changes in price (including differentials and gathering related contract change that effects differentials).

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

- *Extensions.* In 2024, extensions of 16.0 MMBoe were primarily the result of the successful operated drilling program in the Northwest Shelf and Central Basin Platform.

- *Purchase of minerals in place.* In 2024, the Company did not purchase any additional reserves.

- *Sales of minerals in place.* In 2024, the Company sold 1.2 MMBoe from the divestiture of certain oil and gas properties, including vertical wells and associated facilities, within the Central Basin Platform in Andrews and Gaines Counties.

- *Revision of previous quantity estimates.* In 2024, the negative revisions of prior reserves of 3.2 MMBoe consisted of a positive 0.2 MMBoe related to changes in price (including differentials and gathering related contract change that effects differentials), offset by a negative 3.4 MMBoe related to changes in performance and other economic factors.

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

- *Extensions.* In 2023, extensions of 4.8 MMBoe were primarily the result of the successful operated drilling program and non-operated activity in the Northwest Shelf and Central Basin Platform.

- *Purchase of minerals in place.* In 2023, the Company completed the acquisition of 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 Company sold 5.7 MMBoe from the divestiture of 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 quantity estimates.* In 2023, the negative revisions of prior reserves of 9.0 MMBoe consisted of 5.3 MMBoe (59%) related to changes in price and 3.7 MMBoe (41%) related to changes in performance and other economic factors.

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

	As of December 31,		
	2025	2024	2023
Oil (Bbl)			
Developed	60,108,129	56,106,714	56,029,039
Undeveloped	30,211,919	24,797,357	26,112,238
Total	90,320,048	80,904,071	82,141,277
Natural Gas (Mcf)			
Developed	121,424,006	102,538,111	99,896,022
Undeveloped	54,756,570	47,279,051	46,500,300
Total	176,180,576	149,817,162	146,396,322
Natural Gas Liquids (Bbl)			
Developed	23,453,484	19,426,387	15,449,907
Undeveloped	10,140,860	8,876,698	7,768,657
Total	33,594,344	28,303,085	23,218,564
Total (Boe) [(1)]			
Developed	103,798,946	92,622,787	88,128,284
Undeveloped	49,478,875	41,553,897	41,630,945
Total	153,277,821	134,176,684	129,759,229

(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, 2025 and 2024 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, 2025 and 2024, respectively, in accordance with SEC guidelines. As of December 31, 2025, our reserves were based on an SEC average price of $61.82 per Bbl of WTI oil posted and $3.387 per MMBtu of Henry Hub natural gas. As of December 31, 2024, our reserves were based on an SEC average price of $71.96 per Bbl of WTI oil posted and $2.130 per MMBtu Henry Hub natural gas. 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. Prices are adjusted by local field and lease level differentials and are held constant for life of reserves in accordance with SEC guidelines.

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

Standardized Measure of Discounted Future Net Cash Flows

As of December 31,	2025	2024	2023
Future cash inflows	$ 5,976,599,552	$ 6,165,487,616	$ 6,622,410,752
Future production costs	(2,473,482,048)	(2,432,555,200)	(2,413,303,488)
Future development costs [1]	(573,423,296)	(536,825,664)	(562,063,424)
Future income taxes	(402,808,797)	(465,768,645)	(548,664,988)
Future net cash flows	2,526,885,411	2,730,338,107	3,098,378,852
10% annual discount for estimated timing of cash flows	(1,403,392,079)	(1,497,401,764)	(1,699,193,661)
Standardized Measure of Discounted Future Net Cash Flows	$ 1,123,493,332	$ 1,232,936,343	$ 1,399,185,191

(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

	2025	2024	2023
Beginning of the year	$ 1,232,936,343	$ 1,399,185,191	$ 2,272,113,518
Purchase of minerals in place	174,287,315	—	141,738,066
Extensions, discoveries and improved recovery	98,831,276	226,741,618	57,607,609
Development costs incurred during the year	28,098,777	71,665,321	70,697,664
Sales of oil and gas produced, net of production costs	(205,605,448)	(263,830,836)	(266,004,598)
Sales of minerals in place	—	(10,230,951)	(59,600,128)
Accretion of discount	146,282,714	164,703,142	277,365,650
Net changes in price and production costs	(372,012,158)	(285,618,955)	(1,181,594,019)
Net change in estimated future development costs	28,456,200	6,732,428	37,865,811
Revisions of previous quantity estimates	17,046,040	(50,292,499)	(187,443,783)
Changes in estimated timing of cash flows	(60,003,723)	(44,073,556)	(17,257,348)
Net change in income taxes	35,175,996	17,955,440	253,696,749
End of the Year	$ 1,123,493,332	$ 1,232,936,343	$ 1,399,185,191

Our proved reserves by state as of December 31, 2025 are summarized in the table below.

	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)
Texas								
PD	59,958,450	121,037,057	23,372,886	103,504,177	68 %	$ 1,004,059	$ 855,748	$ 134,585
PUD	30,211,919	54,756,570	10,140,860	49,478,875	32 %	311,531	265,514	428,123
Total Proved:	90,170,369	175,793,627	33,513,746	152,983,052	100 %	$ 1,315,590	$ 1,121,262	$ 562,708
New Mexico								
PD	149,679	386,949	80,598	294,769	— %	$ 2,618	$ 2,231	$ 107
PUD	—	—	—	—	— %	—	—	—
Total Proved:	149,679	386,949	80,598	294,769	— %	$ 2,618	$ 2,231	$ 107
Total								
PD	60,108,129	121,424,006	23,453,484	103,798,946	68 %	$ 1,006,677	$ 857,979	$ 134,692
PUD	30,211,919	54,756,570	10,140,860	49,478,875	32 %	311,531	265,514	428,123
Total Proved:	90,320,048	176,180,576	33,594,344	153,277,821	100 %	$ 1,318,208	$ 1,123,493	$ 562,815

Proved Reserves

As of December 31, 2025, we had approximately 153.3 MMBoe of proved reserves, consisting of approximately 59% oil, 19% natural gas, and 22% 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, 2025, approximately 68% of the proved reserves were classified as PD and the remaining 32% were PUD.

As of December 31, 2025, our total proved reserves had a net pre-tax PV-10 value of approximately $1,318.2 million and a Standardized Measure of Discounted Future Net Cash Flows ("SMOG") of approximately $1,123.5 million. Approximately $1,006.7 million pre-tax PV-10 and $858.0 million SMOG, respectively, of total proved reserves are associated with the PD reserves, which is approximately 76% of the total proved reserves' pre-tax PV-10 value. The remaining $311.5 million pre-tax PV-10 and $265.5 million SMOG, respectively, are associated with PUD reserves.

Proved Undeveloped Reserves

Our reserve estimates as of December 31, 2025 include approximately 49.5 MMBoe as PUDs. As of December 31, 2024, our reserve estimates included approximately 41.6 MMBoe as PUDs. In accordance with our December 31, 2025 year-end independent engineering reserve report, we plan to drill our PUD drilling locations within five years of original classification. Below is a description of the changes in our PUD reserves from December 31, 2024 to December 31, 2025.

Notable changes in proved undeveloped reserves for the year ended December 31, 2025 included the following:

- *Conversions to developed.* During the year ended December 31, 2025, we incurred costs of approximately $26.8 million to convert 14 properties from PUD to PD through development. These 14 properties produced 596 MBoe during the year ended December 31, 2025, and have reserves of 3.9 MMBoe as of December 31, 2025.
- *Extensions.* In 2025, extensions of 10.2 MMBoe were primarily the result of the successful operated drilling program in the Northwest Shelf and Central Basin Platform.
- *Purchase of minerals in place.* In 2025, the Company completed the acquisition of Lime Rock oil and gas leases and related property within Andrews County, as well as a few other minor acquisitions, that resulted in 3.1 MMBoe in additional reserves.
- *Sales of minerals in place.* In 2025, we did not sell any PUD reserves.
- *Revision of previous estimates.* In 2025, the negative revisions of prior reserves of 1.4 MMBoe consisted of a negative 3.1 MMBoe related to changes in price (including differentials and gathering related contract change that effects differentials) offset by a positive 1.7 MMBoe related to changes in performance and other economic factors.

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

- *Conversions to developed.* During the year ended December 31, 2024, we incurred costs of approximately $64.7 million to convert 33 properties from PUD to PD through development. These 33 properties produced 893 MBoe during the year ended December 31, 2024, and had reserves of 6.5 MMBoe as of December 31, 2024.
- *Extensions.* In 2024, extensions of 12.8 MMBoe were primarily the result of the successful operated drilling program in the Northwest Shelf and Central Basin Platform.
- *Purchase of minerals in place.* In 2024, we did not purchase any additional reserves.
- *Sales of minerals in place.* In 2024, we sold 0.1 MMBoe from the divestiture of certain oil and gas properties within the Central Basin Platform.
- *Revision of previous estimates.* In 2024, the negative revisions of prior reserves of 5.6 MMBoe consisted of a positive 0.2 MMBoe related to changes in price (including differentials and gathering related contract change that effects differentials) offset by a negative 5.8 MMBoe related to changes in performance and other economic factors.

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, 2023, we incurred costs of approximately $90.3 million to convert 27 properties from PUD to PD through development. These 27 properties produced 573 MBoe during the year ended December 31, 2023, and had reserves of 7.1 MMBoe as of December 31, 2023.
- *Extensions.* In 2023, extensions of 3.7 MMBoe were primarily the result of the successful operated drilling program and non-operated activity in 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 of 4.9 MMBoe consisted of 0.8 MMBoe (16%) related to 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, 2025, no material amount of proved undeveloped reserves were not scheduled to be converted to proved developed status within five years of when they were initially disclosed.

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

Year	Estimated Oil Reserves Developed (Bbl)	Estimated Gas Reserves Developed (Mcf)	Estimated NGL Reserves Developed (Bbl)	Total Boe	Estimated Development Costs (1)
2026	7,544,136	7,167,690	1,826,810	10,565,561	$ 86,869,632
2027	7,864,165	27,456,490	4,177,336	16,617,583	121,567,504
2028	9,502,007	11,447,357	2,345,900	13,755,800	121,346,112
2029	5,301,611	8,685,033	1,790,814	8,539,931	80,044,552
Other Future Years (2)					28,664,584
Total	30,211,919	54,756,570	10,140,860	49,478,875	$ 438,492,384

(1) Estimated Development Costs include future asset retirement costs.

(2) Other Future Years costs include artificial lift conversions, asset retirement obligations and other capital required for the development of these wells.

Preparation and Internal Controls Over Reserves Estimates

All 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, 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 January 22, 2026, filed as an exhibit to this Annual Report, 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 38 years of practical experience in petroleum engineering, with over 36 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 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 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, production data, historical price and cost information, and property ownership interests, and, to a lesser extent, geological maps, well logs, seismic data, and well test data. This data was reviewed by various levels of our management for completeness and 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 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 and Chief Operations Officer, 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 19 years of practical industry experience, including over 15 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, 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 and Chief Operations Officer 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; Vice President and Interim Chief Financial Officer; Executive Vice President and Chief Operations Officer; Senior Vice President of Operations; Executive Vice President and Chief Exploration Officer; and Senior Vice President, General Counsel.

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, and the Audit Committee also meets with CGA annually at a minimum.

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, 2025 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, as it is de minimis.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	84,193	74,717	6,259	4,366	90,452	79,083
Northwest Shelf	12,892	8,833	8,370	8,318	21,262	17,151
Total	97,085	83,550	14,629	12,684	111,714	96,234

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 terms. If production is established on the acreage, the lease will generally remain in effect until the cessation of production from the acreage and is referred to in the industry as 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, 2025, under lease 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					
	2026		2027		2028	
	Gross	Net	Gross	Net	Gross	Net
Central Basin Platform	600	130	963	963	1,628	331
Northwest Shelf	2,030	516	530	527	972	679
Total	2,630	646	1,493	1,490	2,600	1,010

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, 2025, 2024, and 2023:

	Years ended December 31,		
	2025	2024	2023
Oil (Bbls)			
Central Basin Platform	2,974,051	2,851,788	2,347,068
Delaware Basin [1]	—	—	25,743
Northwest Shelf	1,867,113	2,009,840	2,207,131
Total	4,841,164	4,861,628	4,579,942
Natural Gas (Mcf)[1]			
Central Basin Platform	3,825,915	3,808,653	3,940,107
Delaware Basin [1]	—	—	11,265
Northwest Shelf	3,155,043	2,615,021	2,387,786
Total	6,980,958	6,423,674	6,339,158
Natural Gas Liquids (Bbls)			
Central Basin Platform	747,527	749,794	703,818
Delaware Basin [1]	—	—	2,867
Northwest Shelf	640,291	509,020	270,167
Total	1,387,818	1,258,814	976,852
Total production (Boe)			
Central Basin Platform	4,359,231	4,236,357	3,707,571
Delaware Basin [1]	—	—	30,488
Northwest Shelf	3,033,245	2,954,697	2,875,262
Total	7,392,476	7,191,054	6,613,321
Daily production (Boe/d)			
Central Basin Platform	11,943	11,575	10,158
Delaware Basin [1]	—	—	84
Northwest Shelf	8,310	8,073	7,877
Total	20,253	19,648	18,119

[1] 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, 2025, 2024, and 2023.

	Years ended December 31,		
	2025	2024	2023
Average sales price:			
Oil (per Bbl)	$ 63.53	$ 74.87	$ 76.21
Natural gas (per Mcf)	$ (1.33)	$ (1.44)	$ 0.05
NGL (per Bbl)	$ 6.43	$ 9.23	$ 11.95
Total (per Boe)	$ 41.55	$ 50.94	$ 54.60

	Years ended December 31,		
	2025	2024	2023
Average production costs (per Boe):			
Lease operating expenses	$ 10.73	$ 10.89	$ 10.61
Gathering, transportation and processing costs	$ 0.08	$ 0.07	$ 0.07
Ad valorem taxes (including methane tax)	$ 1.07	$ 1.12	$ 1.02
Methane tax [1]	$ (0.07)	$ 0.07	$ —
Ad valorem taxes (excluding methane tax)	$ 1.14	$ 1.05	$ 1.02
Production taxes	$ 1.94	$ 2.24	$ 2.74

[1] In accordance with the IRA, the EPA implemented a waste emission charge ("WEC") on methane emitted from applicable oil and gas facilities that exceed certain thresholds. The methane charge became effective in 2024 at $900 per metric ton of methane, and was set to increase to $1,200 per metric ton of methane for 2025, and $1,500 per metric ton of methane by 2026 and thereafter. For the year ended December 31, 2024, we accrued for $527,687 in methane taxes within Ad valorem taxes in our Statements of Operations. As the WEC was repealed by Congress on March 14, 2025, we reversed the methane tax accrual in the first quarter of 2025.

The average oil sales price amounts above are calculated by dividing revenue from oil sales by the volume of oil sold, in 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 Mcf. The average NGL sales price amounts above are calculated by dividing revenue from NGL sales by the volume of NGLs sold, in 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, 2025 in productive oil and natural gas wells (a net well is our percentage ownership of a gross well). Approximately 99.8% of such wells are in the Permian Basin in Texas.

Oil Wells		Gas wells		Total Wells	
Gross	Net	Gross	Net	Gross	Net
899	742	20	16	919	758

Drilling Activities

During 2025, as operator, we drilled a total of 18.00 gross (17.00 net) wells. Of this, 5.00 gross (4.00 net) horizontal San Andres wells were in the Northwest Shelf in Yoakum County (three 1.0-mile laterals, one 1.25-mile lateral, and one 1.5-mile lateral) and 13.00 gross (13.00 net) wells were in the Central Basin Platform, of which 7.00 were horizontal wells in Andrews County and Crane County, Texas (all 1.0-mile laterals,) and 6.00 were vertical wells in Crane County, and Ector County, Texas. All wells were successful producing oil and gas in commercial quantities.

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

	For the years ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development						
Productive [1]	18.00	17.00	43.00	42.94	31.00	29.75
Dry	—	—	—	—	—	—
Total						
Productive	18.00	17.00	43.00	42.94	31.00	29.75
Dry	—	—	—	—	—	—

[1] One of the 44.00 drilled wells was drilled but not yet completed as of December 31, 2024.

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

	For the years ended December 31,					
	2025		2024		2023	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development						
Productive	—	—	—	—	5.00	0.59
Dry	—	—	—	—	—	—
Total						
Productive	—	—	—	—	5.00	0.59
Dry	—	—	—	—	—	—

Present Activities

We had no wells in the process of being drilled or completed as of December 31, 2025.

Cost Information

We conduct our oil and natural gas activities entirely in the United States. As can be calculated from the table under “Production Prices and Production Costs”, our average production costs including lease operating expenses, gathering, transportation and processing ("GTP") and ad valorem, per Boe, were $11.88, $12.08, and $11.70 for the years ended December 31, 2025, 2024, and 2023 respectively. As shown in the aforementioned table, our average production taxes, per Boe, were $1.94, $2.24, and $2.74 for the years ended December 31, 2025, 2024, and 2023 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, 2025, 2024 and 2023 are shown below:

	2025	2024	2023
Payments to acquire oil and natural gas properties	$ 84,392,361	$ 2,210,826	$ 82,900,900
Payments to explore oil and natural gas properties	—	—	—
Payments to develop oil and natural gas properties	95,207,027	153,945,456	152,559,314
Total costs incurred	$ 179,599,388	$ 156,156,282	$ 235,460,214

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.

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 concluded discovery in the matter and are currently set for trial in the second quarter of 2026.

Item 4: Mine Safety Disclosures

Not applicable.

PART II

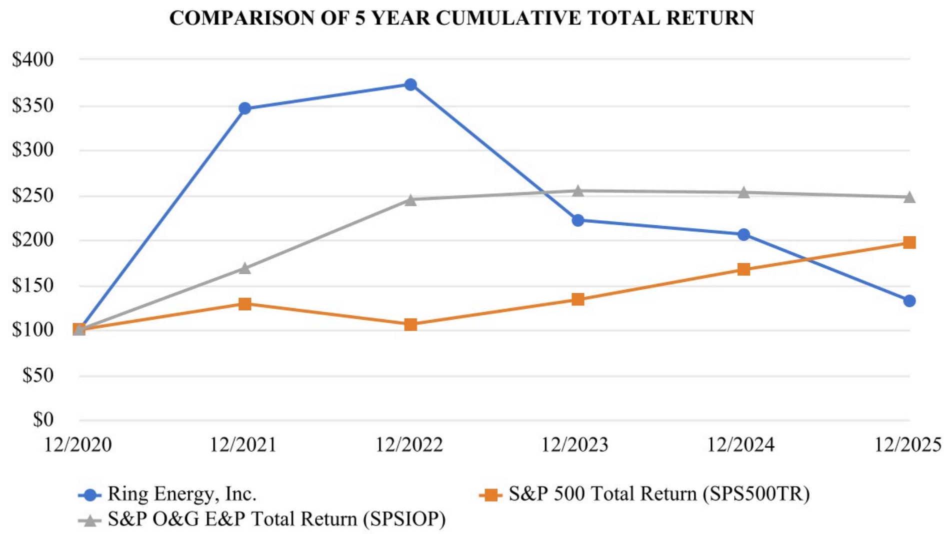
Item 5: Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for our Common Stock

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

Performance Graph

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 and the S&P Oil and Gas Exploration and Production Select Industry Index ("SPSIOP"). The graph assumes the investment of $100 on December 31, 2020 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.



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 4, 2026, there were approximately 73 holders of record of our common stock. This is the number of record holders in the records of 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 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 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 March 31, 2025, filed with the SEC on April 4, 2025, 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, 2025.

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," 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 engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas. Our drilling operations target the oil and liquids rich producing formations in the Northwest Shelf and the Central Basin Platform, in the Permian 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.

- ***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, 2025, the Company made net paydowns of $8 million on its revolving line of credit, resulting in the outstanding long-term debt balance of $420 million.

- ***Employ industry leading drilling and completion techniques***. Ring’s executive team intends to continue 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.

2025 Developments and Highlights

Lime Rock Acquisition

On March 31, 2025, the Company, as buyer, and Lime Rock Resources IV-A, L.P. (“LRRA”), and Lime Rock Resources IV-C, L.P. (“LRRC” and with LRRA, “Lime Rock”), as seller, consummated the transactions contemplated in that certain Purchase and Sale Agreement dated February 25, 2025, by and among the Company, LRRA and LRRC (the “Purchase Agreement”) that was previously reported on Form 8-K filed on February 28, 2025 with the Securities and Exchange Commission (“SEC”). At the closing of the Purchase Agreement, among other things, the Company acquired (the “Lime Rock Acquisition”) interests in oil and gas leases and related property of Lime Rock located in Andrews County, Texas, for an aggregate consideration consisting of: (i) approximately $69.3 million in cash, net of customary purchase price adjustments, paid at the closing of the Lime Rock Acquisition, (ii) $10.0 million in cash paid on December 31, 2025, and (iii) 6,452,879 shares of common stock (the "LRR Shares"). On March 31, 2025, in connection with the closing of the Lime Rock Acquisition, the Company and Lime Rock entered into a customary registration rights agreement relating to the LRR Shares. On May 2, 2025, a registration statement on Form S-3 with respect to the resale of the LRR Shares was declared effective by the SEC.

Credit Agreement

On June 18, 2025, the Company as borrower, Bank of America, N. A. as the Administrative Agent and Issuing Bank (“Bank of America”), and the lenders party thereto (the “Lenders”) entered into the Third Amended and Restated Credit Agreement (the “Credit Agreement”) which amended and restated that certain Second Amended and Restated Credit Agreement dated as of August 31, 2022, by and among the Company, Truist Bank, as administrative agent, and the lenders party thereto, as amended by that certain First Amendment to Second Amended and Restated Credit Agreement, dated as of February 12, 2024 (the “Existing Credit Agreement”). All of the obligations under the Credit Agreement, and the guarantees of those obligations, are secured by substantially all of the Company’s assets. Among other things, the Credit Agreement changed the administrative agent from Truist Bank to Bank of America; reduced the borrowing base and aggregate elected commitment from $600 million to $585 million; extended the maturity date of the Credit Agreement from August 31, 2026 to June 18, 2029; reduced the applicable margin pricing grid by 25 basis points; and made certain administrative changes to the Existing Credit Agreement.

Drilling and Completion

In the first quarter of 2025, in the Northwest Shelf in Yoakum County, the Company drilled and completed three 1-mile horizontal wells and one 1.25-mile horizontal well, all with a working interest of 75%. In the Central Basin Platform in Ector County, the Company drilled and completed three vertical wells, all with a working interest of 100%.

In the second quarter of 2025, in the Central Basin Platform in Andrews County, the Company drilled and completed one 1-mile horizontal well, with a working interest of 100%. Also in the Central Basin Platform in Crane County, the Company drilled and completed one vertical well, with a working interest of 100%.

In the third quarter of 2025, in the Central Basin Platform in Andrews County, the Company drilled and completed three 1-mile horizontal wells, each with a working interest of 100%. Also in the Central Basin Platform in Crane County, the Company drilled and completed one 1-mile horizontal well and one vertical well, both with a working interest of 100%. Finally, the Company began drilling one 1.5-mile horizontal well (with a working interest of 100%) in the Northwest Shelf in Yoakum County.

In the fourth quarter of 2025, the Company finished drilling and completed the aforementioned 1.5-mile horizontal well in the Northwest Shelf. The Company drilled and completed two additional 1-mile horizontal wells in the Central Basin Platform, one in Andrews County and one in Crane County (both with a working interest of 100%). Also in Crane County the Company drilled and completed one vertical well (with a working interest of 100%).

In summary, for 2025, the Company drilled and completed 12 horizontal wells and 6 vertical wells. The table below sets forth our drilling and completion activities for 2025 by quarter, and full year total through December 31, 2025.

Quarter	Area	Wells Drilled	Wells Completed
1Q 2025	Northwest Shelf (Horizontal)	4	4
	Central Basin Platform (Vertical)	3	3
	Total	7	7
2Q 2025	Central Basin Platform (Horizontal)	1	1
	Central Basin Platform (Vertical)	1	1
	Total	2	2
3Q 2025	Central Basin Platform (Horizontal)	4	4
	Central Basin Platform (Vertical)	1	1
	Total	5	5
4Q 2025	Northwest Shelf (Horizontal)	1	1
	Central Basin Platform (Horizontal)	2	2
	Central Basin Platform (Vertical)	1	1
	Total	4	4
FY 2025	Northwest Shelf (Horizontal)	5	5
	Central Basin Platform (Horizontal)	7	7
	Central Basin Platform (Vertical)	6	6
	Total	18	18

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 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.

Average oil and natural gas prices received through 2024 and 2025 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.

Ceiling Test

We perform a ceiling test at the end of each reporting period to evaluate for potential non-cash impairments. Under the full cost method of accounting, the net book value of properties, less related deferred income taxes, may not exceed a calculated “ceiling,” which is defined as the estimated after-tax future net revenues from proved oil and natural gas properties, discounted at an annual rate of 10%. The discounted future net revenues are estimated using spot prices for oil and natural gas, based on the average price during the preceding twelve months. This average is calculated as an unweighted arithmetic mean of the first-day-of-the-month prices for each month within that period, except when changes are fixed and determinable by existing contracts. As a result of the ceiling test, driven by a decrease in the twelve month average commodity prices, the Company recognized a non-cash impairment charge of $108.8 million during the year ended December 31, 2025. If this downward trend continues, the Company's discounted future net revenues could continue to decline, which may trigger additional non-cash impairments recognized in future periods. Estimating potential future non-cash impairments is complex due to numerous factors affecting the ceiling test calculation, including but not limited to future prices, operating costs, upward or downward reserve revisions, reserve additions, and tax attributes. The amount of any additional non-cash impairment, if any, is not estimable at this time given the uncertainty of these factors.

Natural Gas Takeaway Capacity

The Permian Basin has been experiencing a lack of sufficient pipeline transportation for its natural gas production. This has resulted in negative natural gas prices at times, whereby the seller is actually paying the purchaser to take the gas. We experienced negative realized gas prices for all of 2024 and 2025 and conditions are continuing. 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, including tariffs, trade wars, and supply chain disruptions. 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.

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Results of Operations

For the years ended December 31,	2025	2024	2023
Net production:			
Oil (Bbls)	4,841,164	4,861,628	4,579,942
Natural gas (Mcf)	6,980,958	6,423,674	6,339,158
Natural gas liquids (Bbls)	1,387,818	1,258,814	976,852
Net sales:			
Oil	$ 307,553,614	$ 363,971,394	$ 349,044,863
Natural gas	(9,297,614)	(9,265,335)	334,175
Natural gas liquids	8,922,072	11,621,355	11,676,963
Average sales price:			
Oil (per Bbl)	$ 63.53	$ 74.87	$ 76.21
Natural gas (per Mcf)	(1.33)	(1.44)	0.05
Natural gas liquids (Bbl)	6.43	9.23	11.95
Production costs and expenses:			
Lease operating expenses	$ 79,353,806	$ 78,310,949	$ 70,158,227
Gathering, transportation and processing costs	585,087	506,333	457,573
Ad valorem taxes	7,906,586	8,069,064	6,757,841
Oil and natural gas production taxes	14,312,232	16,116,565	18,135,336
Other costs and operating expenses:			
Depreciation, depletion and amortization	$ 96,414,150	$ 98,702,843	$ 88,610,291
Ceiling test impairment	108,825,446	—	—
Asset retirement obligation accretion	1,490,255	1,380,298	1,425,686
Operating lease expense	700,362	700,362	541,801
General and administrative expense ("G&A")	31,928,576	29,640,300	29,188,755
Share-based compensation	6,135,957	5,506,017	8,833,425
G&A excluding share-based compensation	25,792,619	24,134,283	20,355,330
Other income (expense):			
Interest income	$ 290,879	$ 491,946	$ 257,155
Interest (expense)	(40,430,929)	(43,311,810)	(43,926,732)
Gain (loss) on derivative contracts	31,658,839	(2,365,917)	2,767,162
Gain (loss) on disposal of assets	446,400	89,693	(87,128)
Other income	189,294	106,656	198,935
Benefit from (Provision for) Income Taxes	$ 7,452,746	$ (20,440,954)	$ (125,242)

Year Ended December 31, 2025 Compared to Year Ended December 31, 2024

Oil sales. Oil sales decreased approximately $56.4 million to $307.6 million in 2025 from $364.0 million in 2024. This was due to a price variance of approximately $(54.9) million from a decrease in the average realized per barrel oil price to $63.53 in 2025 from $74.87 in 2024. Also impacting the oil sales was a volume variance of approximately $(1.5) million from a decrease in sales volumes to 4,841,164 barrels of oil in 2025 from 4,861,628 barrels of oil in 2024, primarily driven by natural asset decline, offset by production from wells within the assets acquired with the Lime Rock Acquisition (closed in March 2025) and organic growth from workovers, new drills, and other capital expenditures.

Natural gas sales. Natural gas sales remained essentially constant, with approximately $(9.3) million in 2025 and $(9.3) million in 2024. The average realized per Mcf gas price increased to $(1.33) in 2025 from $(1.44) in 2024. The positive change in price was due to an increase in the average gross realized price that was higher than the increase in the average fees. In 2025, the average gross realized price for natural gas was $0.75 per Mcf, and the average fees per Mcf were $(2.08), bringing the net average price to $(1.33) per Mcf. In 2024, the average gross realized price for natural gas was $0.29 per Mcf, and the average fees per Mcf were $(1.73), bringing the net average price to (1.44) per Mcf. The natural gas sales volume increased to 6,980,958 Mcf in 2025 from 6,423,674 Mcf in 2024.

NGL sales. NGL sales decreased approximately $2.7 million to $8.9 million in 2025 from $11.6 million in 2024, due to a price variance of approximately $(3.9) million, as the average realized price per barrel of NGLs was $6.43 in 2025 compared to $9.23 in 2024. This was due to a reduction in the gross realized price per NGL barrel to $18.84 in 2025 compared to $20.00 in 2024 coupled with a growth in the average fees per barrel to $(12.41) in 2025 compared to $(10.77) in 2024. Offsetting this decrease to sales was a volume variance of approximately $1.2 million, as volumes were 1,387,818 barrels of NGLs in 2025 compared to 1,258,814 barrels in 2024, with 82% of the increase in barrels due to the assets acquired in the Lime Rock Acquisition in March 2025.

Lease operating expenses. Our total lease operating expenses (“LOE”) increased approximately $1.0 million to $79.4 million in 2025 from $78.3 million in 2024 and decreased on a Boe basis to $10.73 in 2025 from $10.89 in 2024. These per Boe amounts are calculated by dividing our total LOE by our total volume sold, in Boe. LOE increased due to additional expenses from the assets acquired with the Lime Rock Acquisition (closed in March 2025) which contributed to a 3% increase in production of 201,422 Boe. Specifically, the Company experienced increases of $4.7 million for electrical/utilities costs, $0.7 million for environmental sustainability and cleanup, $0.7 million for communications, and $0.5 million for compressor rentals. This was offset by reductions in costs including $3.1 million for workover expense, $1.0 million for chemicals and treating, $0.6 million for pumping unit repairs, $0.5 million for hot oil paraffin control, $0.2 million for supplies, and $0.2 million for insurance costs.

Gathering, transportation and processing costs. Our total GTP costs increased by $78,754 to $585,087 in 2025 from $506,333 in 2024 and slightly increased on a Boe basis to $0.08 in 2025 from $0.07 in 2024. The increase in costs was $107,637 in gas processing costs, offset by a reduction of $28,883 from NGL processing costs.

Ad valorem taxes. Our total ad valorem taxes decreased approximately $0.2 million to $7.9 million in 2025 from $8.1 million in 2024 and decreased on a Boe basis to $1.07 in 2025 from $1.12 in 2024. Ad valorem taxes decreased due to $1.2 million lower taxes in Yoakum County and $1.1 million for the reversal of the waste emissions charge ("WEC") that was recognized in 2024. This was offset by tax increases of $2.0 million in Andrews County, primarily from properties acquired in the Lime Rock Acquisition, and $0.1 million in Ector County.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales increased to 4.66% in 2025 from 4.40% during 2024. In 2024, an accrual of $1.2 million was made for estimated severance tax refunds expected, which lowered the average rate for 2024. As of December 31, 2024, $0.9 million of the estimated refund was received. Excluding this refund, the overall average percentage of production taxes to oil and gas sales in 2024 was 4.7%, which is in line with the historical rates.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense decreased approximately $2.3 million to $96.4 million in 2025 from $98.7 million in 2024, with $2.2 million of the decrease from reduced depletion on our oil and natural gas properties and $0.1 million from a reduction in amortization of financing lease assets. The $2.2 million decrease in depletion on oil and gas properties is due to a decreased average expense per unit of $12.86 in 2025 from $13.52 in 2024. Produced Boe increased by 201,422 in 2025; however, the reduced expense per unit resulted in lower depletion costs year over year. While average costs of property increased from the Lime Rock Acquisition and other capital well work, the asset impairment in 2025 resulted in a 5% increase in average estimated costs of property change year over year compared to an 11% increase in the amortization base (Boe).

Ceiling test impairment. During 2025, as a result of the lower oil prices impacting the present value of estimated future net revenues, the Company incurred a ceiling test impairment on its oil and natural gas properties of $108.8 million.

Asset retirement obligation accretion. Our asset retirement obligation (“ARO”) accretion increased by $109,957 to $1,490,255 in 2025 from $1,380,298 in 2024. The primary drivers in this increase of ARO accretion were the wells acquired in the Lime Rock Acquisition, which closed in March 2025, as well as new wells drilled in 2025. This was offset by wells plugged and abandoned and sold in 2025.

Operating lease expense. Our operating lease expense was consistent year over year, as the Company experienced no changes in its office leases.

General and administrative expenses (including share-based compensation). General and administrative expenses increased approximately $2.3 million to $31.9 million in 2025 from $29.6 million in 2024. The increase was primarily related to an increase of $2.5 million in salaries, wages, and bonuses, $0.6 million in share-based compensation, and $0.6 million in other professional fees. This was offset by reductions of $0.5 million in environmental sustainability costs, $0.5 million in legal fees, $0.4 million in additional costs capitalized, and $0.1 million in credit loss expense.

Interest income. Interest income decreased by $201,067 to $290,879 in 2025 from $491,946 in 2024. This was driven by a reduction of $184,997 in sweep accounts interest income and $16,070 for severance tax refund interest income.

Interest expense. Interest expense decreased approximately $2.9 million to $40.4 million in 2025 from $43.3 million in 2024. The decrease was primarily due to a 1% decrease in the average interest rate on the Company's long-term credit facility, which was 8.2% in 2025 and 9.2% in 2024, notwithstanding the increase in the Company's average amounts drawn on the same. Other reductions included lower deferred financing costs and interest on royalty suspense. This was offset by an increase in deferred cash payment accretion related to the Lime Rock Acquisition.

Gain (loss) on derivative contracts. During 2025, the Company recognized a gain on derivative contracts of approximately $31.7 million. During 2024, the Company incurred a loss on derivative contracts of approximately $2.4 million. For the derivative contract settlements, the Company recorded a realized gain of $5.5 million during 2025 and a realized loss of $5.2 million during 2024. The change of approximately $10.6 million in the realized derivative settlements was $14.1 million from realized oil derivative settlements and $(3.5) million from realized natural gas derivative settlements. For the marked-to-market contracts, the Company recorded an unrealized gain of $26.2 million during 2025 and an unrealized gain of $2.8 million during 2024. This change of approximately $23.4 million in unrealized derivatives was from $16.5 million in favorable derivative portfolio changes and futures pricing for marked-to-market oil derivative contracts, as well as $6.9 million favorable changes to the marked-to-market natural gas derivative contract balance.

Gain (loss) on disposal of assets. Gain (loss) on disposal of assets increased $356,707 to a gain of $446,400 in 2025 from a gain of $89,693 in 2024. The increase was primarily the result of an increase of $349,442 from the sale of leased vehicles and an increase of $7,265 from the sale of owned vehicles.

Other income. Other income increased $82,638 to $189,294 in 2025 from $106,656 in 2024. The increase was primarily due to income of $150,770 from a pipeline easement lease, offset by a reduction of $68,132 in income from the Company's charge card rebate program.

Benefit from (provision for) income taxes. The provision for income taxes changed to a benefit of $7,452,746 for 2025 from a provision of $20,440,954 for 2024, primarily driven by the change from pre-tax book income in 2024 to a pre-tax book loss in 2025, impacted by the ceiling test impairment recognized in 2025.

Net income (loss). The Company recognized a net loss of $34,731,199 in 2025 compared to net income of $67,470,314 in 2024. The decrease in income associated with operations was due to the reduction in commodity pricing, which reduced revenues as well as led to the ceiling test impairment recognized. Lessening this impact was the gain on derivative contracts, which was positive in terms of both unrealized and realized gains.

Year Ended December 31, 2024 Compared to Year Ended December 31, 2023

Oil sales. Oil sales increased approximately $14.9 million to $364.0 million in 2024 from $349.0 million in 2023. The oil sales increased by a volume variance of approximately $21.5 million from an increase in sales volumes to 4,861,628 barrels of oil in 2024 from 4,579,942 barrels of oil in 2023, primarily driven by production from wells within the assets acquired with the Founders Acquisition (closed in August 2023). Other impacts to revenue volumes include organic growth from workovers, new drills, and other capital expenditures, offset by divestitures completed and natural asset decline. The volume variance was offset by a negative price variance of approximately $(6.5) million from a decrease in the average realized per barrel oil price to $74.87 in 2024 from $76.21 in 2023.

Natural gas sales. Natural gas sales decreased approximately $9.6 million to $(9.3) million in 2024 from $0.3 million in 2023. The natural gas sales decreased by a negative price variance of approximately $(9.6) million, as the average realized per Mcf gas price decreased to $(1.44) in 2024 from $0.05 in 2023. The significant reduction in realized natural gas prices was driven by a lower market index price. In 2024, the average gross realized price for natural gas was $0.29 per Mcf, and the average fees per Mcf were $(1.73), bringing the net average price to $(1.44) per Mcf. 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. This was only slightly offset by the volume variance as the volume increased to 6,423,674 Mcf in 2024 from 6,339,158 Mcf in 2023.

NGL sales. NGL sales decreased approximately $0.1 million to $11.6 million in 2024 from $11.7 million in 2023. NGL sales had a volume variance of approximately $3.4 million, as volumes were 1,258,814 barrels of NGLs in 2024 compared to 976,852 barrels in 2023, with 36% of the increase in barrels due to the assets acquired in the Founders Acquisition in 2023. Offsetting this increase to sales was a negative price variance of approximately $(3.4) million, as the average realized price per barrel of NGLs was $9.23 in 2024 compared to $11.95 in 2023. This was due to a reduction in the gross realized price per NGL barrel to $20.00 in 2024 compared to $21.16 in 2023 coupled with a growth in the average fees per barrel to $(10.77) in 2024 compared to $(9.20) in 2023.

Lease operating expenses. Our total lease operating expenses (“LOE”) increased approximately $8.1 million to $78.3 million in 2024 from $70.2 million in 2023 and increased slightly on a Boe basis to $10.89 in 2024 from $10.61 in 2023. These per Boe amounts are calculated by dividing our total LOE by our total volume sold, in Boe. LOE increased due to the full year of expenses from the assets acquired with the Founders Acquisition (closed in August 2023) which contributed to a 9% increase in production of 577,733 Boe. Specifically, the Company experienced increases of $4.1 million for chemicals and treating, $1.8 million for electrical/utilities costs, $0.6 million for pumping unit repairs, $0.6 million for other employee costs, $0.4 million for environmental sustainability, and $0.4 million for insurance costs.

Gathering, transportation and processing costs. Our total GTP costs increased by $48,760 to $506,333 in 2024 from $457,573 in 2023 and remained unchanged on a Boe basis with $0.07 in 2024 and $0.07 in 2023. The increase in costs was $30,298 from NGL processing costs and $18,462 from gas processing costs.

Ad valorem taxes. Our total ad valorem taxes increased approximately $1.3 million to $8.1 million in 2024 from $6.8 million in 2023 and increased on a Boe basis to $1.12 in 2024 from $1.02 in 2023. Ad valorem taxes increased $1.1 million due to a full year of taxes for the properties acquired in the Founders Acquisition (i.e. Ector County), $0.1 million in Yoakum County, and $0.1 million in Andrews County, offset by a reduction of $0.5 million in Crane County. Additionally, we have accrued approximately $0.5 million for the waste emissions charge ("WEC") in place for the calendar year 2024.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales decreased to 4.40% in 2024 from 5.02% during 2023. In 2024, an accrual of $1.2 million was made for estimated severance tax refunds expected, which lowered the average rate for 2024. As of December 31, 2024, $0.9 million of the estimated refund was received. Excluding this refund, the overall average percentage of production taxes to oil and gas sales in 2024 is 4.7%, which is in line with the historical rates.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased approximately $10.1 million to $98.7 million in 2024 from $88.6 million in 2023, with $9.8 million of the increase from depletion on our oil and natural gas properties, $0.3 million from amortization of financing lease assets, and $0.04 million from depreciation of fixed assets. The increase in depletion was primarily due to a volume variance of $7.6 million was from an increase of 577,733 in Boe produced. Additionally, depletion experienced a price variance of $2.2 million, from a higher depletion expense per unit overall year over year, due to an $18.9 million increase in average estimated costs of property coupled with a 1.6 million reduction in the amortization base (Boe). Our average depreciation, depletion and amortization per Boe increased to $13.73 per Boe during 2024 from $13.40 per Boe during 2023.

Asset retirement obligation accretion. Our asset retirement obligation ("ARO") accretion decreased by $45,388 to $1,380,298 in 2024 from $1,425,686 in 2023. The primary drivers in this reduction of ARO accretion were the sale of our operated New Mexico assets, which closed in September of 2023 and the divestiture of our Delaware Basin assets, which closed in May 2023, along with other wells sold. This was offset by additional ARO accretion from wells acquired in the Founders Acquisition, which closed in August 2023, as well as new wells drilled in 2024.

Operating lease expense. Our operating lease expense increased by $158,561 to $700,362 in 2024 from $541,801 in 2023 due to additional office space leased in The Woodlands office, substantially completed in September 2023.

General and administrative expenses (including share-based compensation). General and administrative expenses increased approximately $0.5 million to $29.6 million in 2024 from $29.2 million in 2023. The increase was primarily related to an increase of $3.1 million increase in salaries, wages, and bonuses in 2024 coupled with the $0.6 million G&A costs reduction in 2023 related to the employee retention tax credit. This was offset by a $3.3 million reduction in share-based compensation.

Interest income. Interest income increased by $234,791 to $491,946 in 2024 from $257,155 in 2023. This was driven by the increase of $239,797 in sweep accounts interest income and $25,834 for severance tax refund interest income, offset by a decrease of $29,042 from the employee retention tax credit interest income of 2023, as well as $1,798 from the interest earned on the escrow deposit made for the Founders Acquisition in 2023.

Interest expense. Interest expense decreased approximately $0.6 million to $43.3 million in 2024 from $43.9 million in 2023. The decrease was primarily the result of the deferred cash payment accretion of $0.6 million which was incurred in 2023, which was not required in 2024. Other changes include reductions in interest from our long-term credit facility, offset by an increase of interest on royalty suspense and deferred financing costs.

Gain (loss) on derivative contracts. During 2024, the Company incurred a loss on derivative contracts of approximately $2.4 million. During 2023, the Company recorded a gain on derivative contracts of approximately $2.8 million. For the derivative contract settlements, the Company recorded a realized loss of $5.2 million during 2024 and a realized loss of $9.1 million during 2023. The decrease of $3.9 million in the realized loss was $1.1 million from realized oil derivative settlements and $2.8 million from realized natural gas derivative settlements. For the marked-to-market contracts, the Company recorded an unrealized gain of $2.8 million during 2024 and an unrealized gain of $11.9 million during 2023. This change of approximately $9.0 million in unrealized derivatives was from $2.6 million in unfavorable derivative portfolio changes and futures pricing for marked-to-market oil derivative contracts, as well as $6.4 million unfavorable changes to the marked-to-market natural gas derivative contract balance.

Gain (loss) on disposal of assets. Gain (loss) on disposal of assets increased $176,821 to a gain of $89,693 in 2024 from a loss of $87,128 in 2023. The increase was primarily the result of the Company recognizing a gain on disposal of assets from selling multiple leased vehicles during 2024, compared with a loss on disposal of assets primarily from selling multiple company owned vehicles during 2023.

Other income. Other income decreased $92,279 to $106,656 in 2024 from $198,935 in 2023. The decrease primarily resulted from the termination of The Woodlands office operating lease in 2023. Offsetting this reduction was a higher bank rebate related to the use of a vendor payment program earned in 2024 compared to 2023.

Provision for income taxes. The provision for income taxes changed to a provision of $20,440,954 for 2024 from a provision of $125,242 for 2023. The provision for income taxes was calculated using the annual effective tax rate method based on our estimated earnings and estimated state and federal income taxes due for 2024, taking into account all applicable tax rates and laws.

Net income. The Company achieved net income of $67,470,314 in 2024 compared to net income of $104,864,641 in 2023. The decrease in income associated with operations was due to increased LOE costs, ad valorem taxes, and depletion, depreciation, and amortization costs. This was offset by increased oil sales and also lower production taxes as a result of prior period refunds. A change in derivatives position from gain to loss further caused the reduction of net income. The 2024 income tax provision was a significant change from year to year impacting the overall decrease in net income realized by the Company.

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 2025 was from funds generated from the sale of oil and natural gas production. These cash flows were primarily used to fund our capital expenditures and pay down our debt balance. 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 June 18, 2025, the Company, as borrower, Bank of America, N.A. as the Administrative Agent and Issuing Bank, and the lenders party thereto (the "Lenders") entered into that certain Third Amended and Restated Credit Agreement (the "Credit Agreement"), with a maximum borrowing base of $1 billion secured by substantially all of the assets of the Company and a maturity date of June 2029.

The Credit Agreement has a borrowing base of $585 million, which is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The borrowing base is redetermined semi-annually each May and 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 and cancellation of certain hedging positions.

The Credit Agreement permits the Company to declare restricted payments (including dividends) for its equity owners, subject to certain limitations, including (a) (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio (outstanding debt to adjusted earnings before interest, income tax expense, depreciation, depletion and amortization, exploration expenses, and all other non-cash charges acceptable to the 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 Credit Agreement), and (iv) the Borrowing Base Utilization Percentage (as defined in the Credit Agreement) is not greater than 80%; or (b) (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio does not exceed 1.50 to 1.00, and (iii) the Borrowing Base Utilization Percentage is not greater than 75%.

The reference rate in the Credit Agreement is the Secured Overnight Financing Rate ("SOFR"). The interest rate on each SOFR Loan will (i) be the adjusted term SOFR for the applicable interest period plus (ii) a margin between 2.75% and 3.75% (depending on the then-current level of borrowing base usage) plus (iii) a 0.10% SOFR adjustment. 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 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) 1.00% per annum, plus (b) a margin between 1.75% and 2.75% per annum (depending on the then-current level of borrowing base usage).

The Credit Agreement contains certain covenants, which, among other things, require the maintenance of (i) a total Leverage Ratio of not more than 3.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Credit Agreement) of 1.0 to 1.0. The 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, and producing oil and gas. However, on any hedge testing date, (a) if the borrowing base utilization is less than 25% and the 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 will be 0% from such hedge testing date to the next succeeding hedge testing date and (b) if the borrowing base utilization percentage is equal to or greater than 25%, but less than 50% and the 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 will be 25% from such hedge testing date to the next succeeding hedge testing date.

As of December 31, 2025, $420 million was outstanding on the Credit Facility and the Company was in compliance with all covenants in the Credit Agreement.

Cash Flows. Historically, primary sources of cash have been from operations, equity offerings and borrowings on the Credit Facility. During 2025, 2024, and 2023 we had net cash provided by operating activities of $150.8 million, $194.4 million, and $198.2 million, respectively. These amounts differed from the Company's income (loss) from operations of $(34.3) million, $132.9 million, and $145.8 million, respectively, for the years ended December 31, 2025, 2024, and 2023, with the difference primarily resulting from the non-cash depletion, depreciation and amortization booked as well as the non-cash ceiling test impairment booked in 2025. During the three years ended December 31, 2025, we financed $12.3 million through proceeds from the sale of common stock. During 2025, 2024, and 2023, the Company had a net draw of $35.0 million, a net repayment of $40.0 million, and a net draw of $10.0 million on the Credit Facility, respectively. We used cash to fund our capital expenditures and development aggregating $571.2 million over the three years ended December 31, 2025. Additionally, during 2025, 2024 and 2023, we used cash of $196.8 million, $170.0 million and $215.0 million, respectively, to reduce the outstanding balance on our Credit Facility. As of December 31, 2025, we had cash on hand of $0.9 million and negative working capital of $38.9 million, compared to cash on hand of $1.9 million and negative working capital of $54.6 million as of December 31, 2024 and cash on hand of $0.3 million and negative working capital of $57.9 million as of December 31, 2023.

Contractual Obligations. Our material cash commitments from known contractual and other obligations consist primarily of obligations for debt and related interest, operating and finance leases, ARO and other obligations as part of normal operations. Certain amounts included in our contractual obligations as of December 31, 2025 are based on our estimates and assumptions about these obligations, including their duration, anticipated actions by third parties and other factors.

The Company maintains a Credit Facility which currently has a $585 million borrowing base. The outstanding balance on that Credit Facility as of December 31, 2025 was $420 million, which will require repayment or refinancing at or prior to maturity in June 2029. Refer to "NOTE 9 — REVOLVING LINE OF CREDIT" in the notes to the financial statements for more information on the Credit Facility.

The Company leases office spaces in The Woodlands, Texas and Midland, Texas. The Woodlands office is currently under a 71-month (five years and 11-month) lease for its office space, effective May 9, 2023. The Midland office is currently under a five-year lease for its office space, effective October 1, 2022 and ending September 30, 2027. Future lease payments for operating leases aggregate $1,497,380.

The Company has financing leases for vehicles with varying maturity dates through 2028. Future lease payments for financing leases aggregate $1,428,999.

Effects of Inflation and Pricing

The oil and natural gas industry is cyclical and the demand for goods and services of oil field companies, suppliers, and others associated with the industry puts 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 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, 2025, the Company 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.

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.

Ceiling Test 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 the year ended December 31, 2025, the Company recorded non-cash write-downs of the carrying value of the Company’s proved oil and natural gas properties as a result of ceiling test limitations of approximately $108.8 million, which is reflected as ceiling test impairment in the accompanying Statements of Operations. The Company did not have any write-downs related to the full cost ceiling limitation during the years ended December 31, 2024 or 2023.

Our estimates of reserves and future cash flow as of December 31, 2025 and 2024 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, 2025 and 2024, respectively, in accordance with SEC guidelines. As of December 31, 2025, our reserves were based on an SEC average price of $61.82 per Bbl of WTI oil posted and $3.387 per MMBtu Henry Hub natural gas. As of December 31, 2024, our reserves were based on an SEC average price of $71.96 per Bbl of WTI oil posted and $2.130 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. Continuing downward trends in SEC pricing could impact the Company's discounted future net revenues, resulting in non-cash impairments in future periods. Due to the complexity and uncertainty in numerous factors affecting the ceiling test calculation, including future prices, operating costs, upward or downward reserve revisions, the amount is not estimable.

Income Taxes. Deferred income taxes are provided on differences between the tax basis of assets and liabilities and their carrying amounts in the financial 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 net operating loss carryforwards during the periods in which the temporary differences become deductible. We also consider the reversal of deferred tax liabilities and available tax planning strategies. As of December 31, 2025 and 2024, the Company did not carry a valuation allowance against its federal and state deferred tax assets.

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 received during 2025 ranged from a monthly average low of $55.46 per barrel to a monthly average high of $73.75 per barrel. Natural gas prices realized during 2025 ranged from a monthly average low of $(3.51) per Mcf to a monthly average high of $1.01 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 $(1.46) per Mcf to a monthly average high of $2.89 per Mcf. Fees ranged from a monthly average low of $(2.35) per Mcf to a monthly average high of $(1.88) per Mcf. NGL prices received during 2025 ranged from a monthly average low of $4.33 per barrel to a monthly average high of $11.34 per barrel. A significant decline in the prices of oil or natural gas 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 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, for the next two years. See "NOTE 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 2026	6,663	–
February 2026	7,252	16,31
March 2026	6,411	14,48
April 2026	6,517	14,72
May 2026	6,204	14,02
June 2026	6,310	14,27
July 2026	6,007	13,61
August 2026	5,914	13,42
September 2026	6,051	13,68
October 2026	5,765	13,07
November 2026	5,867	13,33
December 2026	5,623	12,74
January 2027	5,548	25,17
February 2027	6,071	27,53
March 2027	5,403	24,58
April 2027	5,533	25,11
May 2027	5,290	24,01
June 2027	5,400	24,54
July 2027	4,710	23,47
August 2027	4,645	23,22
September 2027	4,733	23,74
October 2027	4,489	22,73
November 2027	4,590	23,24
December 2027	4,391	22,26

Customer Credit Risk

Our principal exposure to credit risk is through receivables from the sale of our oil and natural gas production (approximately $29.6 million as of December 31, 2025). We are subject to credit risk due to the concentration of our oil and natural gas receivables with our most significant customers, or purchasers. We do not require our purchasers to post collateral, and the inability of our significant purchasers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. The following table sets forth certain information regarding the top three purchasers of our oil, natural gas, and NGLs for the year ended December 31, 2025. We believe that the loss of any of these 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, 2025	December 31, 2025
Purchaser:	Percentage of Oil, Natural Gas, and Natural Gas Liquids Revenues	Percentage of accounts receivables from the sale of our oil and natural gas production
Phillips 66 Company ("Phillips")	67%	66%
Concord Energy LLC ("Concord")	13%	10%
NGL Crude Partners ("NGL Crude")	9%	6%

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, 2025, we had $420 million outstanding on our Credit Facility with a weighted average annual interest rate for the year then ended of 8.2%. A 1% change in the interest rate on our Credit Facility would result in an estimated $4.2 million change in our annual interest expense. See "NOTE 9 — REVOLVING LINE OF CREDIT" in the notes to the financial statements for more information on the Company’s interest rates 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 Interim 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 Interim 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, 2025, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Interim 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 Interim Chief Financial Officer have concluded that as of December 31, 2025, 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, 2025 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

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, 2025, 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, 2025. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2025, 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, 2025, 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, 2025, 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, 2025, and our report dated March 4, 2026 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 4, 2026

Item 9B: Other Information

During the quarter ended December 31, 2025, none of our directors or officers (as defined in Rule 16a-1(f) of the Securities Exchange Act of 1934) adopted, terminated or modified a Rule 10b5-1 trading arrangement or non-Rule 10b5-1 trading arrangement (as such terms are defined in Item 408 of Regulation S-K).

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, including information on our insider trading policy under the caption "Insider Trading Policy," is incorporated by reference herein from the Company's 2026 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2025. 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 2026 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2025. 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 2026 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2025. 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 2026 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2025. 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 2026 Proxy Statement to be filed with the SEC no later than 120 days after December 31, 2025. 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	Furn-ished Here-with
2.1	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	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		
2.4	Purchase and Sale Agreement dated as of February 25, 2025 by and among Ring Energy, Inc., Lime Rock Resources IV-A, L.P., and Lime Rock Resources IV-C, L.P.	8-K	001-36057	2.1	2/28/25		
3.1	Articles of Incorporation (as amended)	10-K	000-53920	3.1	4/1/13		
3.2	Certificate of Amendment to the Articles of Incorporation, as amended, of Ring Energy, Inc.	8-K	001-36057	3.1	12/17/21		
3.3	Certificate of Amendment to the Articles of Incorporation, as amended, of Ring Energy, Inc.	8-K	001-36057	3.1	5/26/23		
3.4	Bylaws of Ring Energy, Inc. as amended April 13, 2021	8-K	001-36057	3.1	4/15/21		
3.5	Certificate of Designation of the Series A Convertible Preferred Stock dated August 30, 2022	8-K	001-36057	3.1	9/6/22		
3.6	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	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	4.2	3/7/24		
4.2	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		
10.1(a)*	Consulting Agreement, dated July 1, 2024 by and between Ring Energy, Inc. and Stephen D. Brooks.	8-K	001-36957	10.1	7/3/24		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Here-with	Furn-ished Here-with
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*	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		
10.8	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		
10.9	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		
10.10	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		
10.11*	Ring Energy, Inc. 2021 Omnibus Incentive Plan	DEF 14A	001-36057		4/22/21		
10.12*	Amendment No. 1 to the Ring Energy, Inc. 2021 Omnibus Incentive Plan	8-K	001-36057	10.1	5/26/23		
10.13*	Form of Performance Stock Unit Agreement	8-K	001-36057	10.1	11/30/21		
10.14*	Form Restricted Stock Unit Agreement (employees)	8-K	001-36057	10.1	2/23/23		
10.15*	Form of Restricted Stock Unit Agreement (non-employee directors)	8-K	001-36057	10.2	2/23/23		
10.16	Form of Warrant Amendment and Exercise Agreement.	8-K	001-36057	10.1	4/12/23		
10.17	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		
10.18	Change in Control and Severance Benefit Plan	10-K	001-36057	10.25	3/7/24		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit	Filing Date	Filed Here-with	Furn-ished Here-with
10.19	Registration Rights Agreement dated March 31, 2025, by and among Ring Energy, Inc., Lime Rock Resources IV-A, L.P. and Lime Rock Resources IV-C, L.P.	8-K	001-36057	10.1	4/4/25		
10.20	Amendment No. 2 to the Ring Energy, Inc. 2021 Omnibus Incentive Plan.	8-K	001-36057	10.1	5/22/25		
10.21	Third Amended and Restated Credit Agreement dated June 18, 2025, by and among Ring Energy, Inc., Bank of America, N.A., and the Lenders from time to time party thereto.	8-K	001-36057	10.1	6/23/25		
10.22*	General Release Agreement dated October 2, 2025 by Travis T. Thomas.	8-K/A	001-36057	10.1	10/3/25		
10.23*	Offer Letter between Ring Energy, Inc. and Sundip S. Johl dated January 29, 2026.	8-K	001-36057	10.1	2/3/26		
14.1	Code of Ethics	8-K	000-53920	14.1	1/24/13		
19.1	Insider Trading Policy	10-K	001-36057	19.1	3/5/25		
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 Principal Financial Officer					X	
32.1	Section 1350 Certification of Chief Executive Officer						X
32.2	Section 1350 Certification of Principal Financial Officer						X
97.1	Ring Energy, Inc. Clawback Policy	10-K	001-36057	97.1	3/7/24		
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).						

* 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 4, 2026

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 attorney-in-fact and agent, 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 or her signature as he or she 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
Mr. Paul D. McKinney
Chief Executive Officer and Director
(Principal Executive Officer)
Date: March 4, 2026

/s/ Thomas L. Mitchell
Mr. Thomas L. Mitchell
Director
Date: March 4, 2026

/s/ Rocky P. Kwon
Mr. Rocky P. Kwon
Vice President, Chief Accounting Officer
(Principal Financial Officer and Principal Accounting Officer)
Date: March 4, 2026

/s/ Anthony B. Petrelli
Mr. Anthony B. Petrelli
Director
Date: March 4, 2026

/s/ Carla Tharp
Mrs. Carla Tharp
Director
Date: March 4, 2026

/s/ John A. Crum
Mr. John A. Crum
Director
Date: March 4, 2026

/s/ Richard E. Harris
Mr. Richard E. Harris
Director
Date: March 4, 2026

/s/ David S. Habachy
Mr. David S. Habachy
Director
Date: March 4, 2026

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, 2025 and 2024, the related statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2025, 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, 2025 and 2024, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2025, 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, 2025, 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 4, 2026 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 matter

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 a separate opinion 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 and impairment expense under the full cost method of accounting

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 development costs to calculate and record depletion, depreciation and amortization expense and impairment expense. To estimate the volume of proved crude oil and natural gas reserves, future development costs, and the related future net cash flows, 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 and the assessment of potential impairment. We identified the estimation of proved reserves of oil and gas properties as a critical audit matter.

The principal consideration for our determination that the estimation of proved crude oil and natural gas reserves is a critical audit matter is that changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volumes, future development costs, and the related net cash flows of the Company's proved reserves could have a significant impact on the measurement of depletion, depreciation and amortization expense and impairment 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 key 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 impairment 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 reserve engineers.
- Identified the inputs and assumptions significant to the proved reserve volumes and tested management's process for determining the significant inputs and assumptions, including examining the underlying support on a sample basis. Specifically, our audit procedures involved testing management's inputs and assumptions by performing the following:
    - 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;
    - Tested models used to estimate the future operating costs in the reserve report and compared amounts to historical operating costs;
    - 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;
    - Tested, on a sample basis, the working and net revenue interests used in the reserve report by inspecting land, legal and division order records;
    - 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; and
    - Applied analytical procedures to production forecasts in the reserve report by comparing to historical actual results.

/s/ GRANT THORNTON LLP

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

Houston, Texas

March 4, 2026

RING ENERGY, INC.
BALANCE SHEETS

As of December 31,	2025	2024
ASSETS		
Current Assets		
Cash and cash equivalents	$ 902,913	$ 1,866,395
Accounts receivable	30,938,908	36,172,316
Joint interest billing receivables, net	1,623,991	1,083,164
Derivative assets	21,468,134	5,497,057
Inventory	5,312,715	4,047,819
Prepaid expenses and other assets	1,822,751	1,781,341
Total Current Assets	62,069,412	50,448,092
Properties and Equipment		
Oil and natural gas properties, full cost method	1,891,510,431	1,809,309,848
Financing lease asset subject to depreciation	3,633,586	4,634,556
Fixed assets subject to depreciation	3,504,788	3,389,907
Total Properties and Equipment	1,898,648,805	1,817,334,311
Accumulated depreciation, depletion and amortization	(569,180,901)	(475,212,325)
Net Properties and Equipment	1,329,467,904	1,342,121,986
Operating lease asset	1,285,159	1,906,264
Derivative assets	9,739,430	5,473,375
Deferred financing costs	9,337,344	8,149,757
Total Assets	$ 1,411,899,249	$ 1,408,099,474
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 97,522,809	$ 95,729,261
Income tax liability	356,436	328,985
Financing lease liability	730,564	906,119
Operating lease liability	586,614	648,204
Derivative liabilities	841,193	6,410,547
Notes payable	505,752	496,397
Asset retirement obligations	418,526	517,674
Total Current Liabilities	100,961,894	105,037,187
Non-current Liabilities		
Deferred income taxes	20,764,119	28,591,802
Revolving line of credit	420,000,000	385,000,000
Financing lease liability, less current portion	593,146	647,078
Operating lease liability, less current portion	819,223	1,405,837
Derivative liabilities	2,512,692	2,912,745
Asset retirement obligations	29,972,429	25,864,843
Total Liabilities	575,623,503	549,459,492
Commitments and contingencies - See Note 13		
Stockholders' Equity		
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; 207,656,929 shares and 198,561,378 shares issued and outstanding, respectively	207,657	198,561
Additional paid-in capital	812,777,586	800,419,719
Retained earnings (Accumulated deficit)	23,290,503	58,021,702
Total Stockholders' Equity	836,275,746	858,639,982
Total Liabilities and Stockholders' Equity	$ 1,411,899,249	$ 1,408,099,474

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

RING ENERGY, INC.
STATEMENTS OF OPERATIONS

For the years ended December 31,	2025	2024	2023
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 307,178,072	$ 366,327,414	$ 361,056,001
Costs and Operating Expenses			
Lease operating expenses	79,353,806	78,310,949	70,158,227
Gathering, transportation and processing costs	585,087	506,333	457,573
Ad valorem taxes	7,906,586	8,069,064	6,757,841
Oil and natural gas production taxes	14,312,232	16,116,565	18,135,336
Depreciation, depletion and amortization	96,414,150	98,702,843	88,610,291
Ceiling test impairment	108,825,446	—	—
Asset retirement obligation accretion	1,490,255	1,380,298	1,425,686
Operating lease expense	700,362	700,362	541,801
General and administrative expense	31,928,576	29,640,300	29,188,755
Total Costs and Operating Expenses	341,516,500	233,426,714	215,275,510
Income (Loss) from Operations	(34,338,428)	132,900,700	145,780,491
Other Income (Expense)			
Interest income	290,879	491,946	257,155
Interest (expense)	(40,430,929)	(43,311,810)	(43,926,732)
Gain (loss) on derivative contracts	31,658,839	(2,365,917)	2,767,162
Gain (loss) on disposal of assets	446,400	89,693	(87,128)
Other income	189,294	106,656	198,935
Net Other Income (Expense)	(7,845,517)	(44,989,432)	(40,790,608)
Income (Loss) Before Benefit from (Provision for) Income Taxes	(42,183,945)	87,911,268	104,989,883
Benefit from (Provision for) Income Taxes	7,452,746	(20,440,954)	(125,242)
Net Income (Loss)	$ (34,731,199)	$ 67,470,314	$ 104,864,641
Basic Earnings (Loss) per Share	$ (0.17)	$ 0.34	$ 0.55
Diluted Earnings (Loss) per Share	$ (0.17)	$ 0.34	$ 0.54

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

RING ENERGY, INC.
STATEMENT OF STOCKHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
	Shares	Amount			
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	4,517,427	4,517	3,609,424	—	3,613,941
Induced exercise of common warrants issued in offering	14,512,166	14,512	8,673,143	—	8,687,655
Restricted stock vested	1,680,232	1,680	(1,680)	—	—
Shares to cover tax withholdings for restricted stock vested	(288,152)	(287)	287	—	—
Payments to cover tax withholdings for restricted stock vested, net	—	—	(520,153)	—	(520,153)
Performance stock vested	1,170,024	1,170	(1,170)	—	—
Shares to cover tax withholdings for performance stock vested	(284,908)	(285)	285	—	—
Share-based compensation	—	—	8,833,425	—	8,833,425
Net income	—	—	—	104,864,641	104,864,641
Balance, December 31, 2023	196,837,001	$ 196,837	$ 795,834,675	$ (9,448,612)	$ 786,582,900
Restricted stock vested	1,688,317	1,688	(1,688)	—	—
Shares to cover tax withholdings for restricted stock vested	(327,041)	(327)	327	—	—
Payments to cover tax withholdings for restricted stock vested, net	—	—	(919,249)	—	(919,249)
Performance stock vested	571,324	571	(571)	—	—
Shares to cover tax withholdings for performance stock vested	(208,223)	(208)	208	—	—
Share-based compensation	—	—	5,506,017	—	5,506,017
Net income	—	—	—	67,470,314	67,470,314
Balance, December 31, 2024	198,561,378	$ 198,561	$ 800,419,719	$ 58,021,702	$ 858,639,982
Restricted stock vested	2,402,692	2,403	(2,403)	—	—
Shares to cover tax withholdings for restricted stock vested	(588,840)	(589)	589	—	—
Payments to cover tax withholdings for restricted stock vested, net	—		(1,189,805)	—	(1,189,805)
Common stock issuance for Lime Rock Acquisition	6,452,879	6,453	7,414,358	—	7,420,811
Performance stock vested	1,230,565	1,231	(1,231)	—	—
Shares to cover tax withholdings for performance stock vested	(401,745)	(402)	402	—	—
Share-based compensation	—	—	6,135,957	—	6,135,957
Net loss	—	—	—	(34,731,199)	(34,731,199)
Balance, December 31, 2025	207,656,929	$ 207,657	$ 812,777,586	$ 23,290,503	$ 836,275,746

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

RING ENERGY, INC.
STATEMENTS OF CASH FLOWS

For the years ended December 31,	2025	2024	2023
Cash Flows From Operating Activities			
Net income (loss)	$ (34,731,199)	$ 67,470,314	$ 104,864,641
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	96,414,150	98,702,843	88,610,291
Ceiling test impairment	108,825,446	—	—
Asset retirement obligation accretion	1,490,255	1,380,298	1,425,686
Amortization of deferred financing costs	4,459,520	4,969,174	4,920,714
Share-based compensation	6,135,957	5,506,017	8,833,425
Credit loss expense	19,029	160,847	134,007
(Gain) loss on disposal of assets	(446,400)	(89,693)	—
Deferred income tax expense (benefit)	(7,858,446)	19,935,413	(425,275)
Excess tax expense (benefit) related to share-based compensation	30,763	104,344	478,304
(Gain) loss on derivative contracts	(31,658,839)	2,365,917	(2,767,162)
Cash received (paid) for derivative settlements, net	5,452,300	(5,193,673)	(9,084,920)
Changes in operating assets and liabilities:			
Accounts receivable	4,452,926	3,594,504	1,154,085
Inventory	(1,264,896)	2,089,116	3,113,782
Prepaid expenses and other assets	(41,410)	93,509	226,688
Accounts payable	474,744	(5,076,738)	(1,451,422)
Settlement of asset retirement obligation	(904,493)	(1,588,480)	(1,862,385)
Net Cash Provided by Operating Activities	150,849,407	194,423,712	198,170,459
Cash Flows From Investing Activities			
Payments for the Stronghold Acquisition	—	—	(18,511,170)
Payments for the Founders Acquisition	—	—	(62,227,145)
Payments for the Lime Rock Acquisition	(81,863,429)	—	—
Payments to purchase oil and natural gas properties	(2,528,932)	(2,210,826)	(2,162,585)
Payments to develop oil and natural gas properties	(95,207,027)	(153,945,456)	(152,559,314)
Payments to acquire or improve fixed assets subject to depreciation	(179,771)	(185,524)	(492,317)
Proceeds from sale of fixed assets subject to depreciation	17,360	10,605	332,229
Proceeds from divestiture of oil and natural gas properties	100	121,232	1,554,558
Proceeds from sale of Delaware properties	—	—	7,600,699
Proceeds from sale of New Mexico properties	—	(144,398)	3,891,757
Proceeds from sale of CBP vertical wells	—	5,500,000	—
Insurance proceeds received for damage to oil and natural gas properties	260,446	—	—
Net Cash Used in Investing Activities	(179,501,253)	(150,854,367)	(222,573,288)
Cash Flows From Financing Activities			
Proceeds from revolving line of credit	231,822,997	130,000,000	225,000,000
Payments on revolving line of credit	(196,822,997)	(170,000,000)	(215,000,000)
Proceeds from issuance of common stock and warrants	—	—	12,301,596
Payments for taxes withheld on vested restricted shares, net	(1,189,805)	(919,249)	(520,153)
Proceeds from notes payable	1,648,539	1,560,281	1,637,513
Payments on notes payable	(1,639,184)	(1,597,618)	(1,603,659)
Payment of deferred financing costs	(5,647,107)	(88,450)	(52,222)
Reduction of financing lease liabilities	(484,079)	(954,298)	(776,388)
Net Cash Provided by (Used in) Financing Activities	27,688,364	(41,999,334)	20,986,687
Net Increase (Decrease) in Cash	(963,482)	1,570,011	(3,416,142)
Cash at Beginning of Period	1,866,395	296,384	3,712,526
Cash at End of Period	$ 902,913	$ 1,866,395	$ 296,384

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

For the years ended December 31,	2025	2024	2023
Supplemental Cash Flow Information			
Cash paid for interest	$ 32,363,614	$ 39,196,575	$ 38,009,164
Cash paid (refunded) for income taxes	347,487	72,213	72,213
Noncash Investing and Financing Activities			
Asset retirement obligation incurred during development	$ 89,923	$ 695,553	$ 439,528
Asset retirement obligation acquired	2,780,280	—	2,090,777
Asset retirement obligation revision of estimate	(78,480)	133,794	53,826
Asset retirement obligation sold	(65,129)	(3,219,651)	(5,340,211)
Operating lease assets obtained in exchange for new operating lease liability	—	—	1,713,677
Financing lease assets obtained in exchange for new financing lease liability, net [(1)]	707,964	738,240	894,996
Change in capitalized expenditures attributable to drilling projects financed through current liabilities	1,039,445	(3,896,948)	(2,241,192)
Supplemental Schedule for Lime Rock Acquisition			
Investing Activities - Cash Paid			
Cash paid to Lime Rock on closing	$ 63,599,939	$ —	$ —
Escrow deposit released at closing	5,000,000	—	—
Direct transaction costs	2,576,648	—	—
Cash paid for fixed assets acquired	(34,275)	—	—
Purchase price adjustments paid to third parties	1,427,233	—	—
Cash received from Lime Rock for post-close adjustments	(706,116)	—	—
Payment of deferred cash payment	10,000,000	—	—
Payments for the Lime Rock Acquisition	$ 81,863,429	$ —	$ —
Investing Activities - Noncash			
Assumption of suspense liability	$ 459,096	$ —	$ —
Assumption of ad valorem tax liability	405,549	—	—
Assumption of asset retirement obligation	2,587,179	—	—
Deferred cash payment at fair value	9,415,066	—	—
Financing Activities - Noncash			
Common stock issued for acquisition	7,420,811	—	—
Supplemental Schedule for Founders Acquisition			
Investing Activities - Cash Paid			
Escrow deposit released at closing	$ —	$ —	$ 7,500,000
Closing amount paid to Founders	—	—	42,502,799
Interest from escrow deposit	—	—	1,747
Direct transaction costs	—	—	1,361,843
Post-close adjustments	—	—	(4,139,244)
Payment of deferred cash payment	—	—	15,000,000
Payments for the Founders Acquisition	$ —	$ —	$ 62,227,145
Investing Activities - Noncash			
Assumption of suspense liability	$ —	$ —	$ 677,116
Assumption of asset retirement obligation	—	—	2,090,777
Assumption of ad valorem tax liability	—	—	234,051
Deferred cash payment at fair value	—	—	14,657,383
Supplemental Schedule for Stronghold Acquisition			
Investing Activities - Cash Paid			
Payment of deferred cash payment	—	—	15,000,000
Payment of post-close settlement	—	—	3,511,170
Payments for the Stronghold Acquisition	$ —	$ —	$ 18,511,170

(1) Included within the financing lease assets obtained in exchange for new financing lease liability, net, is $144,216 and $45,436 of finance lease asset terminations for the years ended December 31, 2025 and 2024, respectively.

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 engaged in oil and natural gas development, production, acquisition, and exploration activities currently focused in the Permian Basin of Texas. Our drilling operations target the oil and liquids rich producing formations in the Northwest Shelf and the Central Basin Platform, in the Permian Basin in Texas.

Liquidity and Capital Considerations – The Company strives to maintain an adequate liquidity level to address volatility and risk. Sources of liquidity include the Company's net cash provided by operating 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 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 some extent by the Company's hedge contracts.

The Company believes that it has the ability to continue to fund its operations and 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 our revolving line of credit approximate their fair value because the underlying instruments are at interest rates which approximate current market rates. The carrying amounts of 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 Receivables – Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and receivables.

Cash and cash equivalents – The Company had cash in excess of federally insured limits of $652,913 and $1,616,395 as of December 31, 2025 and 2024, 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. Refer to the "*Major Purchasers*" section below for detail on purchaser activity for the years ended December 31, 2025, 2024, and 2023.

The following table reflects the Company's beginning and ending balances of its accounts receivables from purchasers of its oil and gas for the years ended December 31, 2025, 2024, and 2023.

	For the years ended December 31,		
	2025	2024	2023
Beginning balance of accounts receivable from purchasers of oil and gas	$ 33,774,968	$ 37,879,779	$ 40,143,326
Ending balance of accounts receivable from purchasers of oil and gas	29,591,571	33,774,968	37,879,779

Joint interest billing receivables, net – The Company also has joint interest billing receivables. 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 credit loss expense associated with its joint interest billing receivables during the years ended December 31, 2025, 2024, and 2023.

	For the years ended December 31,		
	2025	2024	2023
Credit loss expense	$19,029	$160,847	$134,007

The following table reflects the Company's joint interest billing receivables and allowance for credit losses as of December 31, 2025 and 2024.

	2025	2024
Joint interest billing receivables	$ 1,824,753	$ 1,264,897
Allowance for credit losses	(200,762)	(181,733)
Joint interest billing receivables, net	$ 1,623,991	$ 1,083,164

The increase of $19,029 in the allowance for credit losses during the year ended December 31, 2025 was primarily for owner settlements considered uncollectible with no offsetting revenues held in suspense.

For receivables, the Company's estimated credit loss allowance is estimated using historical loss information, current industry conditions and payment practices, as well as reasonable and supportable forecasts of future economic conditions. Credit risk is assessed based on days outstanding and other available information.

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, 2025 or 2024.

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, 2025 and 2024, the Company had no such investments.

Inventory – The full balance of the Company's inventory consists of materials and supplies for its operations, with no work in process or finished goods 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. The Company reports the balance of its inventory at the lower of cost or 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, 2025, 2024, and 2023.

	For the years ended December 31,		
	2025	2024	2023
Depletion	$ 95,079,057	$ 97,238,673	$ 87,442,546
Depletion rate, per barrel-of-oil-equivalent (Boe)	$ 12.86	$ 13.52	$ 13.22

In addition, capitalized costs less accumulated depletion and related deferred income taxes 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.

Due to the lower oil prices impacting the present value of estimated future net revenues, during the year ended December 31, 2025, the Company recorded impairments on oil and natural gas properties as a result of the ceiling test of $108.8 million. No impairments on oil and natural gas properties as a result of the ceiling test were recorded for the years ended December 31, 2024 or 2023.

Land, Buildings and Structures, Equipment, Software, Leasehold Improvements, Automobiles, and UAV – Land, buildings and structures, equipment, software, leasehold improvements, automobiles, and unmanned aerial vehicles ("UAV") are carried at historical cost, adjusted for impairment loss and accumulated depreciation (except for land). Historical costs include all direct costs associated with the acquisition of land, buildings and structures, equipment, software, leasehold improvements, automobiles, and UAV 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 and structures, equipment, software, leasehold improvements, automobiles, and UAV 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
UAV	3 years

The following table provides information on the Company's depreciation expense for the years ended December 31, 2025, 2024, and 2023.

	For the years ended December 31,		
	2025	2024	2023
Depreciation expense	$409,474	$405,772	$364,024

During the years ended December 31, 2025 2024, and 2023, the Company recorded a gain (loss) on disposal of assets, which was impacted by the sale of owned vehicles, as follows:

	For the years ended December 31,		
	2025	2024	2023
Sale of owned vehicles	$ (6,974)	$ (14,239)	$ (132,109)
Sale of leased vehicles	453,374	103,932	44,981
Gain (loss) on disposal of assets	**$ 446,400**	**$ 89,693**	**$ (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, 2025 and 2024:

	2025	2024
Trade accounts payable	$ 40,196,719	$ 39,289,431
Revenues payable	37,156,219	35,766,989
Accrued expenses	20,169,871	20,672,841
Accounts payable	**$ 97,522,809**	**$ 95,729,261**

Trade accounts payable – The following table summarizes the Company's current trade accounts payable at December 31, 2025 and 2024:

	2025	2024
Accounts payable related to vendors	$ 33,012,524	$ 37,147,926
Other	7,184,195	2,141,505
Trade accounts payable	**$ 40,196,719**	**$ 39,289,431**

Revenues payable – The following table summarizes the Company's current revenues and royalties payable at December 31, 2025 and 2024:

	2025	2024
Revenue held in suspense	$ 32,107,446	$ 28,166,335
Revenues and royalties payable	5,048,773	7,600,654
Revenues payable	**$ 37,156,219**	**$ 35,766,989**

Accrued expenses – The following table summarizes the Company's current accrued expenses at December 31, 2025 and 2024:

	2025	2024
Accrued capital expenditures	$ 4,395,906	$ 3,645,377
Accrued lease operating expenses	5,149,712	5,313,315
Accrued interest	5,853,412	2,830,440
Accrued general and administrative expense	4,685,253	4,897,904
Other	85,588	3,985,805
Accrued expenses	**$ 20,169,871**	**$ 20,672,841**

Notes Payable – At the end of May 2025, the Company renewed its control of well, general liability, pollution, umbrella, property, worker's compensation, auto, and D&O (directors and officers) insurance policies, funding the premiums with a promissory note with a face value after down payments of $1,648,539. The APR for this note was 7.75%. In November 2025, the Company renewed its cybersecurity insurance policy, paying the premium without financing through a note.

At the end of May 2024, the Company renewed its control of well, general liability, pollution, umbrella, property, workers' compensation, auto, and D&O insurance policies, funding the premiums with a promissory note with a face value after down payments of $1,501,507. In November 2024, the Company renewed its cybersecurity insurance policy, and funded the premium with a promissory note with a face value after down payments of $58,773. The APR for both notes was 7.98%.

At the end of May 2023, the Company renewed its control of well, general liability, pollution, umbrella, property, workers' compensation, auto, and D&O insurance policies, and funded the premiums with a promissory note with a total face value after down payments of $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 was 7.08%.

As of December 31, 2025 and 2024, the notes payable balances included within current liabilities on the Balance Sheets were $505,752 and $496,397, respectively.

The following table reflects the weighted average notes payable balances and the weighted average interest rate on the weighted average notes payable outstanding during the period as of and for the years ended December 31, 2025, 2024, and 2023.

	For the years ended December 31,		
	2025	2024	2023
Weighted average notes payable balance	$ 688,086	$ 651,789	$ 687,456
Weighted average interest rate on weighted average notes payable	8.59 %	8.63 %	7.23 %

The following table shows interest paid related to notes payable for the years ended December 31, 2025, 2024, and 2023. This interest is included within "Interest (expense)" in the Statements of Operations.

	For the years ended December 31,		
	2025	2024	2023
Interest paid for notes payable	$ 59,097	$ 56,261	$ 49,734

Revenue Recognition –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 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 (quality, transportation and other variables from benchmark prices). The 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 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. 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 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.

On July 4, 2025, the One Big Beautiful Bill Act ("OBBBA") was enacted, which, among other items, allows for 100% bonus depreciation on a permanent basis for property acquired after January 19, 2025. Further, the OBBBA basis for Code

Section 163(j) net interest expense deduction is based on EBITDA (earnings before interest, taxes, depreciation and amortization) rather than EBIT (earnings before interest and taxes) for taxable years beginning after December 31, 2024, and any disallowed interest expense can be carried forward indefinitely. We have incorporated these changes into our income tax provision for the year ended December 31, 2025.

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. The Company has identified its federal income tax return and its franchise tax return in Texas in which it operates as a "major" tax jurisdiction. The Company's federal income tax returns for the years ended December 31, 2022 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 2021 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 of Operations.

Leases **–** Upon adoption of ASU 2016-02, the Company made accounting policy elections to not capitalize leases with a lease term of twelve months or less (i.e. 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 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 adoption. 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 applicable period. Diluted earnings (loss) per share are calculated to give effect to potentially issuable dilutive common shares.

Major Purchasers – During the year ended December 31, 2025, sales to three purchasers represented 67%, 13%, and 9%, respectively, of total oil, natural gas, and natural gas liquids sales. As of December 31, 2025, sales outstanding from these three purchasers represented 66%, 10%, and 6%, respectively, of accounts receivable from purchasers. During the year ended December 31, 2024, sales to three purchasers represented 61%, 14%, and 13%, respectively, of total oil, natural gas and natural gas liquids sales. As of December 31, 2024, sales outstanding from these three purchasers represented 64%, 11%, and 11%, respectively, of accounts receivable from 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 from purchasers.

Share-Based Employee Compensation **–** The Company has outstanding stock option grants, restricted stock unit awards, and performance stock unit awards to directors, officers and employees, which are described more fully below in "NOTE 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 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, 2025, 2024, and 2023.

	For the years ended December 31,		
	2025	2024	2023
Share-based compensation	$6,135,957	$5,506,017	$8,833,425

Derivative Instruments and Hedging Activities – The Company periodically 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 7 — DERIVATIVE FINANCIAL INSTRUMENTS" for 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 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 provided optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships, subject to meeting certain criteria, that referenced LIBOR ("London Inter-Bank Offered Rate") or another rate. ASU 2020-04 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. The Company adopted ASU 2020-04 with an effective date of January 1, 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 reference rate. At this time, the Company does not plan to enter into additional contracts using LIBOR as a reference rate. As such, 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 Accounting Standards Codification ("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.

In November 2023, the FASB issued ASU 2023-07 "*Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*." This update requires that a public entity with multiple reportable segments disclose significant segment expenses that are regularly provided to the 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 reportable segment's profit or loss currently required by Topic 280 in interim periods. Although a public entity is permitted to 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 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 280. The amendments in this update became effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. The Company adopted ASU 2023-07 effective January 1, 2024.

In December 2023, the FASB issued ASU 2023-09 "*Income Taxes (Topic 740): Improvements to Income Tax Disclosures*." The amendments from this update 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 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), 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. For public business entities, the amendments in this update are effective for annual periods beginning after December 15, 2024. As such, the Company adopted ASU 2023-09 effective January 1, 2025. The Company has included the applicable enhanced disclosures prospectively in its annual financial statements for the year ended December 31, 2025.

In March 2024, the FASB issued ASU 2024-02 "*Codification Improvements – Amendments to Remove References to the Concepts Statements*" ("ASU 2024-02"), which contains amendments to the Codification to remove references to various FASB Concepts Statements. In most instances, the references are extraneous and not required to understand or apply the guidance. Generally, ASU 2024-02 is not intended to result in significant accounting changes for most entities. ASU 2024-02 is effective for the Company for fiscal years beginning after December 15, 2024. As such, the Company adopted ASU 2024-02 effective January 1, 2025. The adoption did not have a material impact on the Company's financial statements.

Recent Accounting Pronouncements – In October 2023, the FASB issued ASU 2023-06, "*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 2024, the FASB issued ASU 2024-03, "*Income Statement - Reporting Comprehensive Income - Expenses Disaggregation Disclosures (Subtopic 220-40) - Disaggregation of Income Statement Expenses"* ("ASU 2024-03"). The purpose of this update is to improve the disclosures about a public business entity's expenses and address requests from investors for more detailed information about the types of expenses (including purchases of inventory, employee compensation, depreciation, amortization, and depletion) in commonly presented expense captions (such as cost of sales, SG&A, and research and development). As clarified in ASU 2025-01, "Income Statement – Reporting Comprehensive Income – Expenses Disaggregation Disclosures (Subtopic 220-40) – Clarifying the Effective Date," the amendments in this update are effective for annual reporting periods beginning after December 15, 2026, and interim reporting periods within annual reporting periods beginning after December 15, 2027, with early adoption permitted, and either prospective or retrospective application permitted. The Company is currently assessing the impact of adopting this new guidance on its financial disclosures.

In July 2025, the FASB issued ASU 2025-05, "*Financial Instruments - Credit Losses (Topic 326) - Measurement of Credit Losses for Accounts Receivable and Contract Assets*," that provides for a practical expedient for estimating expected credit losses which assumes that current conditions as of the balance sheet date do not change for the remaining life of the asset. The amendments will be effective prospectively for annual reporting periods beginning after December 15, 2025, and interim periods within those annual reporting periods. The Company is currently assessing the impact of adopting this new guidance on its financial disclosures.

In December 2025, the FASB issued ASU 2025-11, "*Interim Reporting (Topic 270) - Narrow-Scope Improvements*," which provides clarity on the current interim disclosure requirements. The update also includes the addition of a disclosure principle which requires entities to disclose events since the last annual reporting period that have a material impact on the entity. The application of the update is effective for interim reporting periods within annual reporting periods beginning after December 15, 2027, with early adoption permitted, and either prospective or retrospective application permitted. The Company is currently assessing the impact of adopting this new guidance on its interim financial disclosures.

NOTE 2 — REVENUE RECOGNITION

The Company predominantly derives its revenue from the sale of produced crude oil, natural gas, and NGLs. The contractual performance obligation is satisfied when the product is delivered to the 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 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. Once consideration is received from the purchaser, the Company records any variances between the estimates and actual amounts, which has historically not been significant.

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 majority of the Company's natural gas sales processing contracts, the Company delivers unprocessed natural gas to midstream processing entities at the wellhead, and the midstream processing entities obtain control of the natural gas and NGLs at the wellhead. The midstream processing entities gather and process the natural gas and NGLs and remit 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 purchasers 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.

The Company has only one minor contract with a natural gas processing entity in place where the point of control does not pass at the wellhead. Under this agreement, the point of control of the gas dictates that the associated fees are recorded as an expense.

Disaggregation of revenue. The following table presents revenues disaggregated by product for the years ended December 31, 2025, 2024, and 2023.

	For the years ended December 31,		
	2025	2024	2023
Oil, Natural Gas, and Natural Gas Liquids Revenues			
Oil	$ 307,553,614	$ 363,971,394	$ 349,044,863
Natural gas [1]	(9,297,614)	(9,265,335)	334,175
Natural gas liquids	8,922,072	11,621,355	11,676,963
Total oil, natural gas, and natural gas liquids revenues	$ 307,178,072	$ 366,327,414	$ 361,056,001

[1] In 2024 and 2025, the Company experienced a net negative total gas revenue, due to the significant reduction in gross realized sales prices per Mcf, coupled with the growth in the plant fees per Mcf.

NOTE 3 — LEASES

The Company has operating leases for its offices in Midland, Texas and The Woodlands, Texas. The current Midland office is under a five-year lease, effective October 1, 2022 and ending September 30, 2027. The Woodlands office is currently under a 71-month (five years and 11-month) lease, effective May 9, 2023. The future payments for these office spaces are reflected in the future lease payments schedule below.

The Company has month to month leases for office equipment and compressors used in 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 an initial 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 are settled in cash or applied to a new vehicle.

Future lease payments associated with these operating and financing leases as of December 31, 2025 are as follows:

	2026	2027	2028	2029	2030	Thereafter	Total
Operating lease payments	$ 636,649	$ 460,497	$ 250,606	$ 149,628	$ —	$ —	$ 1,497,380
Financing lease payments	803,745	465,880	159,374	—	—	—	1,428,999

The following table shows the weighted average remaining lease term and the weighted average discount rate for the Company's leases as of the dates indicated.

	As of December 31,	
	2025	2024
Operating leases		
Weighted average remaining lease term (in years)	2.71	3.45
Weighted average discount rate	4.50 %	4.50 %
Finance leases		
Weighted average remaining lease term (in years)	1.99	1.85
Weighted average discount rate	7.50 %	7.31 %

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,	
	2025	2024
Operating lease liability, current portion	$ 586,614	$ 648,204
Operating lease liability, non-current portion	819,223	1,405,837
Operating lease liability, total	**$ 1,405,837**	**$ 2,054,041**
Total undiscounted future cash flows (sum of future operating lease payments)	$ 1,497,380	$ 2,224,840
Imputed interest	91,543	170,799
Undiscounted future cash flows less imputed interest	**$ 1,405,837**	**$ 2,054,041**
Financing lease liability, current portion	$ 730,564	$ 906,119
Financing lease liability, non-current portion	593,146	647,078
Financing lease liability, total	**$ 1,323,710**	**$ 1,553,197**
Total undiscounted future cash flows (sum of future financing lease payments)	$ 1,428,999	$ 1,667,763
Imputed interest	105,289	114,566
Undiscounted future cash flows less imputed interest	**$ 1,323,710**	**$ 1,553,197**

The following table provides supplemental information regarding lease costs in the Statements of Operations for the years ended December 31, 2025, 2024, and 2023.

	2025	2024	2023
Operating lease costs	$ 700,362	$ 700,362	$ 541,801
Short-term lease costs [1]	$ 4,714,675	$ 4,083,088	$ 5,096,723
Financing lease costs:			
Amortization of financing lease assets [2]	$ 925,619	$ 1,058,398	$ 803,721
Interest on financing lease liabilities [3]	$ 107,754	$ 121,293	$ 101,269

(1) Amount included in Lease operating expenses

(2) Amount included in Depreciation, depletion and amortization

(3) Amount included in Interest (expense)

During the years ended December 31, 2025, 2024, and 2023, the Company recorded a gain (loss) on disposal of assets, which was impacted by the sale of leased vehicles, as follows:

	For the years ended December 31,		
	2025	2024	2023
Sale of owned vehicles	$ (6,974)	$ (14,239)	$ (132,109)
Sale of leased vehicles	453,374	103,932	44,981
Gain (loss) on disposal of assets	**$ 446,400**	**$ 89,693**	**$ (87,128)**

NOTE 4 — EARNINGS (LOSS) PER SHARE INFORMATION

The following table presents the calculation of the Company's basic and diluted earnings (loss) per share for the years ended December 31, 2025, 2024 and 2023. For all dilutive securities, the treasury stock method of calculating the incremental shares is applied.

For the years ended December 31,	2025	2024	2023
Net Income (Loss)	$ (34,731,199)	$ 67,470,314	$ 104,864,641
Basic Weighted-Average Shares Outstanding	204,984,223	197,937,683	190,589,143
Effect of dilutive securities:			
Stock options	—	—	—
Restricted stock units	—	1,695,791	1,292,582
Performance stock units	—	603,867	438,818
Common warrants	—	40,039	3,044,307
Diluted Weighted-Average Shares Outstanding	204,984,223	200,277,380	195,364,850
Basic Earnings (Loss) per Share	$ (0.17)	$ 0.34	$ 0.55
Diluted Earnings (Loss) per Share	$ (0.17)	$ 0.34	$ 0.54

The following table presents the securities which were excluded from the Company's computation of diluted earnings (loss) per share for the years ended December 31, 2025, 2024 and 2023, as their effect would have been anti-dilutive.

	2025	2024	2023
Anti-dilutive securities:			
Stock options to purchase common stock	62,433	66,511	264,966
Unvested restricted stock units	5,211,248	32,231	56,153
Unvested performance stock units	2,822,081	1,260,595	1,445,804

NOTE 5 — ACQUISITIONS & DIVESTITURES

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 "Stronghold Purchase Agreement"). Pursuant to the Stronghold 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 on the sixth-month anniversary of the closing date. 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 million to $600 million at the closing of the Stronghold Acquisition. The remaining consideration consisted of 21,339,986 shares of 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. 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.

Delaware Basin Divestiture

On May 11, 2023, the Company completed the divestiture of its Delaware Basin assets to an unaffiliated party for $8.3 million. The sale had an effective date of March 1, 2023. The final cash consideration was approximately $7.6 million. As part of the divestiture, the buyer assumed an asset retirement obligation balance of 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 Founders 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 $11.9 million paid on December 18, 2023, net of customary purchase price adjustments.

The Founders Acquisition was 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 cash consideration of approximately $3.6 million. 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 certain oil and gas properties in 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 sales 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.

CBP Vertical Well Sale

On September 30, 2024, the Company completed the sale of certain oil and gas properties, including vertical wells and associated facilities, within Andrews County, Texas and Gaines County, Texas to an unaffiliated party for a sales price of $5.5 million, with cash consideration being the same. As part of the sale, the buyer assumed an asset retirement obligation balance of approximately $2.7 million.

Yoakum County Purchase

On December 24, 2024, the Company completed the purchase of assorted leases and additional well interests in Yoakum County, Texas from an unaffiliated party for approximately $1.4 million. The purchase had an effective date of December 1, 2024 with a required down payment of $175,000 due at closing and the remainder of $1,175,000 due in January 2025.

Lime Rock Acquisition

On February 25, 2025, the Company, as buyer, and Lime Rock Resources IV-A, L.P. (“LRRA”) and Lime Rock Resources IV-C, L.P. ("LRRC" and with LRRA, "Lime Rock"), as seller, entered into a purchase and sale agreement (the “Purchase Agreement”), which provided that the Company would acquire (the “Lime Rock Acquisition”) interests in oil and gas leases and related property of Lime Rock located in the Central Basin Platform of the Texas Permian Basin in Andrews County, Texas (the "Lime Rock Assets"). On March 31, 2025, the Company and Lime Rock consummated the transactions contemplated in the Lime Rock Acquisition whereby the Company acquired the Lime Rock Assets for aggregate consideration consisting of: (i) approximately $69.3 million in cash, net of customary purchase price adjustments, paid at the closing of the Lime Rock Acquisition, (ii) $10.0 million paid on December 31, 2025, and (iii) 6,452,879 shares of common stock.

The Lime Rock Acquisition was accounted for as an asset acquisition in accordance with ASC 805. The fair value of the consideration paid by Ring and allocation to the underlying assets acquired, on a relative fair value basis, was recorded as of the date of the closing of the Lime Rock Acquisition. Additionally, costs directly related to the Lime Rock 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 Lime Rock's oil and gas properties. The inputs and assumptions related to the oil and gas properties were categorized as level 3 in the fair value hierarchy.

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

Consideration:		
Common stock consideration		
Shares of common stock issued		6,452,879
Common stock price as of March 31, 2025	$	1.15
Total common stock consideration	$	7,420,811
Cash consideration		
Escrow deposit released at closing	$	5,000,000
Closing amount paid to Lime Rock		63,599,939
Fair value of deferred payment liability		9,415,066
Post-close adjustments		721,116
Total cash consideration	$	78,736,121
Direct transaction costs		2,576,648
Total consideration	**$**	**88,733,580**
Fair value of assets acquired:		
Oil and natural gas properties	$	92,111,309
Fixed assets		34,275
Joint interest billing receivable		39,820
Amount attributable to assets acquired	$	92,185,404
Fair value of liabilities assumed:		
Suspense liability	$	459,096
Asset retirement obligations		2,587,179
Ad valorem tax liability		405,549
Amount attributable to liabilities assumed	$	3,451,824
Net assets acquired	**$**	**88,733,580**

NOTE 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:

Capitalized Costs

As of December 31,	2025	2024	2023
Oil and natural gas properties, full cost method			
Proved properties	$ 1,891,510,431	$ 1,809,309,848	$ 1,663,548,249
Unproved properties	—	—	—
Total oil and natural gas properties, full cost method	$ 1,891,510,431	$ 1,809,309,848	$ 1,663,548,249
Accumulated depletion of oil and natural gas properties	(564,169,311)	(469,786,336)	(373,280,583)
Net oil and natural gas properties capitalized	$ 1,327,341,120	$ 1,339,523,512	$ 1,290,267,666

Costs Incurred in Oil and Gas Producing Activities

For the years ended December 31,	2025	2024	2023
Payments to acquire oil and natural gas properties	$ 84,392,361	$ 2,210,826	$ 82,900,900
Payments to explore oil and natural gas properties	—	—	—
Payments to develop oil and natural gas properties	95,207,027	153,945,456	152,559,314
Total costs incurred	$ 179,599,388	$ 156,156,282	$ 235,460,214

NOTE 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 costless collars, deferred premium puts, or swaps for this purpose. Oil derivative contracts are based on WTI crude oil prices and natural gas contacts are based on the Henry 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. 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 are with lenders under our 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. Although the counterparties hold the right to offset (i.e. netting) the settlement amounts with the Company, in accordance with ASC 815-10-50-4B, the Company classifies the fair value of all its derivative positions on a gross basis in the Company's 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.

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

	As of December 31,	
	2025	2024
Commodity derivative instruments, marked to market:		
Derivative assets, current	**$ 21,468,134**	**$ 5,497,057**
Derivative assets, noncurrent	**$ 9,739,430**	**$ 5,473,375**
Derivative liabilities, current	**$ 841,193**	**$ 6,410,547**
Derivative liabilities, noncurrent	**$ 2,512,692**	**$ 2,912,745**

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,		
	2025	2024	2023
Oil derivatives:			
Realized gain (loss) on oil derivatives	$ 3,834,312	$ (10,264,202)	$ (11,364,484)
Unrealized gain (loss) on oil derivatives	23,367,255	6,859,929	9,462,374
Gain (loss) on oil derivatives	$ 27,201,567	$ (3,404,273)	$ (1,902,110)
Natural gas derivatives:			
Realized gain (loss) on natural gas derivatives	$ 1,617,988	$ 5,070,529	$ 2,279,564
Unrealized gain (loss) on natural gas derivatives	2,839,284	(4,032,173)	2,389,708
Gain (loss) on natural gas derivatives	$ 4,457,272	$ 1,038,356	$ 4,669,272
Gain (loss) on derivative contracts	$ 31,658,839	$ (2,365,917)	$ 2,767,162

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

	For the years ended December 31,		
	2025	2024	2023
Cash flows from operating activities			
Cash received (paid) for oil derivatives	$ 3,834,312	$ (10,264,202)	$ (11,364,484)
Cash received (paid) for natural gas derivatives	1,617,988	5,070,529	2,279,564
Cash received (paid) for derivative settlements, net	$ 5,452,300	$ (5,193,673)	$ (9,084,920)

The following tables reflect the details of current derivative contracts as of December 31, 2025 (quantities are in barrels (Bbl) for the oil derivative contracts and in million British thermal units (MMBtu) for the natural gas derivative contracts).

Oil Hedges (WTI)	**Q1 2026**	**Q2 2026**	**Q3 2026**	**Q4 2026**	**Q1 2027**	**Q2 2027**	**Q3 2027**	**Q4 2027**
Swaps:								
Hedged volume (Bbl)	608,350	577,101	171,400	529,000	509,500	492,000	432,000	412,963
Weighted average swap price	$ 67.95	$ 66.50	$ 62.26	$ 65.34	$ 62.82	$ 60.45	$ 61.80	$ 57.59
Two-way collars:								
Hedged volume (Bbl)	—	—	379,685	—	—	—	—	—
Weighted average put price	$ —	$ —	$ 60.00	$ —	$ —	$ —	$ —	$ —
Weighted average call price	$ —	$ —	$ 72.50	$ —	$ —	$ —	$ —	$ —

Gas Hedges (Henry Hub)	**Q1 2026**	**Q2 2026**	**Q3 2026**	**Q4 2026**	**Q1 2027**	**Q2 2027**	**Q3 2027**	**Q4 2027**
NYMEX Swaps:								
Hedged volume (MMBtu)	448,854	1,165,628	600,016	1,072,305	439,678	423,035	1,079,906	1,046,151
Weighted average swap price	$ 4.19	$ 3.82	$ 4.19	$ 3.99	$ 4.02	$ 4.02	$ 3.86	$ 4.02
Two-way collars:								
Hedged volume (MMBtu)	456,850	139,000	648,728	128,000	717,000	694,000	—	—
Weighted average put price	$ 3.50	$ 3.50	$ 3.10	$ 3.50	$ 3.99	$ 3.00	$ —	$ —
Weighted average call price	$ 5.11	$ 5.42	$ 4.24	$ 5.42	$ 5.21	$ 4.32	$ —	$ —

Gas Hedges (Henry Hub)	**Q1 2028**	**Q2 2028**	**Q3 2028**	**Q4 2028**	**Q1 2029**	**Q2 2029**	**Q3 2029**	**Q4 2029**
NYMEX Swaps:								
Hedged volume (MMBtu)	1,012,567	984,322	956,865	931,539	908,117	886,933	866,585	846,134
Weighted average swap price	$ 3.77	$ 3.77	$ 3.77	$ 3.77	$ 3.67	$ 3.67	$ 3.67	$ 3.67

Gas Hedges (basis differential)	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027	Q3 2027	Q4 2027
El Paso Permian Basin basis swaps:								
Hedged volume (MMBtu)	—	—	—	—	960,307	636,710	615,547	596,306
Weighted average spread price [(1)]	$ —	$ —	$ —	$ —	$ 0.72	$ 0.67	$ 0.67	$ 0.67
Waha basis swaps:								
Hedged volume (MMBtu)	—	—	—	—	196,372	480,325	464,360	449,846
Weighted average spread price [(1)]	$ —	$ —	$ —	$ —	$ 0.78	$ 0.78	$ 0.78	$ 0.78

Gas Hedges (basis differential)	Q1 2028	Q2 2028	Q3 2028	Q4 2028	Q1 2029	Q2 2029	Q3 2029	Q4 2029
El Paso Permian Basin basis swaps:								
Hedged volume (MMBtu)	577,163	561,064	545,413	530,977	517,628	505,552	493,953	482,296
Weighted average spread price [(1)]	$ 0.60	$ 0.60	$ 0.60	$ 0.60	$ 0.57	$ 0.57	$ 0.57	$ 0.57
Waha basis swaps:								
Hedged volume (MMBtu)	435,403	423,259	411,453	400,562	390,490	381,381	372,632	363,837
Weighted average spread price [(1)]	$ 0.68	$ 0.68	$ 0.68	$ 0.68	$ 0.63	$ 0.63	$ 0.63	$ 0.63

[(1)] The gas basis swap hedges are calculated as the Henry Hub natural gas price less the fixed amount specified as the weighted average spread price above.

NOTE 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 7 — DERIVATIVE FINANCIAL INSTRUMENTS").

	Fair Value Measurement Classification			
	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, 2024				
Commodity Derivatives - Assets	$ —	$ 10,970,432	$ —	$ 10,970,432
Commodity Derivatives - Liabilities	—	(9,323,292)	—	(9,323,292)
Total	$ —	$ 1,647,140	$ —	$ 1,647,140
As of December 31, 2025				
Commodity Derivatives - Assets	$ —	$ 31,207,564	$ —	$ 31,207,564
Commodity Derivatives - Liabilities	—	(3,353,885)	—	(3,353,885)
Total	$ —	$ 27,853,679	$ —	$ 27,853,679

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 9 — REVOLVING LINE OF CREDIT

On June 18, 2025, the Company, as borrower, Bank of America, N.A. as the Administrative Agent and Issuing Bank, and the lenders party thereto (the "Lenders") entered into that certain Third Amended and Restated Credit Agreement (the "Credit Agreement"), with a maximum borrowing base of $1 billion secured by substantially all of the assets of the Company and a maturity date of June 2029.

The Credit Agreement has a borrowing base of $585 million, which is subject to periodic redeterminations, mandatory reductions and further adjustments from time to time. The borrowing base is redetermined semi-annually each May and 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 and cancellation of certain hedging positions.

The Credit Agreement permits the Company to declare restricted payments (including dividends) for its equity owners, subject to certain limitations, including (a) (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio (outstanding debt to adjusted earnings before interest, income tax expense, depreciation, depletion and amortization, exploration expenses, and all other non-cash charges acceptable to the 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 Credit Agreement), and (iv) the Borrowing Base Utilization Percentage (as defined in the Credit Agreement) is not greater than 80%; or (b) (i) no default or event of default has occurred or will occur upon such payments, (ii) the pro forma Leverage Ratio does not exceed 1.50 to 1.00, and (iii) the Borrowing Base Utilization Percentage is not greater than 75%.

The reference rate in the Credit Agreement is the Secured Overnight Financing Rate ("SOFR"). The interest rate on each SOFR Loan will (i) be the adjusted term SOFR for the applicable interest period plus (ii) a margin between 2.75% and 3.75% (depending on the then-current level of borrowing base usage) plus (iii) a 0.10% SOFR adjustment. 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 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) 1.00% per annum, plus (b) a margin between 1.75% and 2.75% per annum (depending on the then-current level of borrowing base usage).

The Credit Agreement contains certain covenants, which, among other things, require the maintenance of (i) a total Leverage Ratio of not more than 3.0 to 1.0 and (ii) a minimum ratio of Current Assets to Current Liabilities (as such terms are defined in the Credit Agreement) of 1.0 to 1.0. The 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, and producing oil and gas. However, on any hedge testing date, (a) if the borrowing base utilization is less than 25% and the 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 will be 0% from such hedge testing date to the next succeeding hedge testing date and (b) if the borrowing base utilization percentage is equal to or greater than 25%, but less than 50% and the 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 will be 25% from such hedge testing date to the next succeeding hedge testing date.

As of December 31, 2025, $420 million was outstanding on the Credit Facility and the Company was in compliance with all covenants in the Credit Agreement.

Under the 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, 2025, the Company's unused line of credit was $165.0 million, which was calculated by subtracting the outstanding Credit Facility balance of $420 million and standby letters of credit of $35,000 in total ($10,000 with a federal agency and $25,000 with an insurance company for New Mexico state surety bonds) from the $585 million borrowing base.

NOTE 10 — ASSET RETIREMENT OBLIGATION

The Company records the obligation to plug and abandon oil and gas wells at the dates properties are either acquired or the wells are drilled. The asset retirement obligation is adjusted each quarter for any liabilities incurred or settled during the period, accretion expense, and any revisions made to the costs or timing estimates. The asset retirement obligation is incurred using an annual credit-adjusted risk-free discount rate at the applicable dates. A reconciliation of the asset retirement obligation for the years ended December 31, 2025, 2024 and 2023 is as follows:

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
Liabilities incurred	695,553
Liabilities sold	(3,219,651)
Liabilities settled	(855,561)
Revision of estimate [(1)]	133,794
Accretion expense	1,380,298
Balance, December 31, 2024	$ 26,382,517
Liabilities acquired	2,780,280
Liabilities incurred	89,923
Liabilities sold	(65,129)
Liabilities settled	(208,411)
Revision of estimate [(1)]	(78,480)
Accretion expense	1,490,255
Balance, December 31, 2025	$ 30,390,955

(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 revisions recorded during the year ended December 31, 2025 included updated interests for our working interest partners. The revisions recorded during the years ended December 31, 2024 and 2023 were related to shorter estimated useful lives, with regards to planned dates to plug and abandon such assets.

The following table presents the Company's current and non-current asset retirement obligation balances as of the dates specified.

	December 31, 2025	December 31, 2024
Asset retirement obligations, current	$ 418,526	$ 517,674
Asset retirement obligations, non-current	29,972,429	25,864,843
Asset retirement obligations	$ 30,390,955	$ 26,382,517

NOTE 11 — STOCKHOLDERS' EQUITY

The Company 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 19,107,793 Common Warrants outstanding as of December 31, 2022.

During February and March 2023, a total of 4,517,427 Common 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 common warrants (the “Participating Holders”) entered into a form of Warrant Amendment and Exercise Agreement (the “Exercise Agreement”) pursuant to which the Company agreed to reduce the exercise price of an aggregate of 14,512,166 common warrants held by such Participating Holders from $0.80 to $0.62 per share (the “Reduced Exercise Price”) in consideration for the immediate exercise of the 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 common warrants by the Participating Holders pursuant to the Exercise Agreement, which was recognized as an equity issuance cost in accordance with ASC 815-40-35-17(a). In the Statement of Stockholders' Equity, the 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. No Common Warrants were exercised during 2024, so a total of 78,200 Common Warrants remained outstanding as of December 31, 2024. In October 2025, the remaining 78,200 Common Warrants expired, and as such, no Common Warrants remained outstanding as of December 31, 2025.

NOTE 12 — EMPLOYEE STOCK OPTIONS, RESTRICTED STOCK AWARD PLAN, AND 401(K)

Share-based compensation expense charged against income during the years ended December 31, 2025, 2024, and 2023 was as follows. These amounts are included in General and administrative expense in the Statements of Operations.

	For the years ended December 31,		
	2025	2024	2023
Share-based compensation expense from:			
Employee stock options	$ —	$ —	$ —
Restricted stock unit grants	4,214,928	3,544,748	4,537,026
Performance stock unit awards	1,921,029	1,961,269	4,296,399
Total share-based compensation	**$ 6,135,957**	**$ 5,506,017**	**$ 8,833,425**

During the year ended December 31, 2025, one former executive officer separated from the Company. As part of the executive officer's separation agreement, the vesting of the officer's outstanding performance stock units and restricted stock units were accelerated. The impact to share-based compensation expense resulting from this modification was $133,671.

During the year ended December 31, 2024, two former executive officers separated from the Company, with both officers forfeiting their performance stock units. One officer entered into a consulting agreement with the Company which modified his restricted stock unit agreements to continue to vest through March 31, 2025. The other officer forfeited his restricted stock units. The total forfeitures related to these executive officers separating from the Company resulted in a reduction to share-based compensation expense of $1,448,076.

In 2011, the Board of Directors (the "Board") of the Company approved and adopted a long-term incentive plan (the "2011 Plan"), which was subsequently approved and amended by the shareholders. As of December 31, 2025, there were no shares eligible for grant, either as stock options or as restricted stock, under the 2011 Plan.

In 2021, the Board and Company stockholders approved and adopted the Ring Energy, Inc. 2021 Omnibus Incentive Plan (the "2021 Plan"). 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 of Stockholders, the stockholders approved an amendment to the 2021 Plan to increase the number of shares available under the 2021 Plan by 6.0 million. At the 2025 Annual Meeting of Stockholders, the stockholders approved a second amendment to the 2021 Plan to increase the number of shares available under the 2021 Plan by 11.5 million. As of December 31, 2025, there were 11,785,291 shares available for grant under the 2021 Plan.

Employee Stock Options – No stock options were granted in the years ended December 31, 2025, 2024, or 2023. 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, 2025, 2024, and 2023 and changes during the years ended December 31, 2025, 2024, and 2023 is as follows:

	2025		2024		2023	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	65,500	$ 10.70	70,500	$ 10.33	265,500	$ 4.21
Granted	—	—	—	—	—	—
Forfeited	—	—	—	—	—	—
Expired	(14,500)	12.51	(5,000)	5.50	(195,000)	2.00
Exercised	—	—	—	—	—	—
Outstanding at end of year	51,000	$ 10.18	65,500	$ 10.70	70,500	$ 10.33
Exercisable at end of year	51,000	$ 10.18	65,500	$ 10.70	70,500	$ 10.33

As of December 31, 2025, 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, 2025 was $0. The aggregate intrinsic value of options exercisable at December 31, 2025 was $0. The year-end intrinsic values are based on a December 31, 2025 closing stock price of $0.87.

No stock options were exercised during 2025, 2024 or 2023.

The following table summarizes information related to the Company's stock options outstanding as of December 31, 2025:

	Options Outstanding		
Exercise price	Number Outstanding	Weighted-Average Remaining Contractual Life (in years)	Number Exercisable
6.42	15,000	0.10	15,000
11.75	36,000	0.67	36,000
$ 10.18	51,000	0.77	51,000

Restricted Stock Unit Grants – Following is a table reflecting the restricted stock unit grants during 2025, 2024 and 2023:

Grant date	Restricted stock units granted
February 16, 2023	2,270,842
February 13, 2024	2,647,970
April 5, 2024	60,000
July 31, 2024	76,600
December 9, 2024	83,000
February 12, 2025	3,691,373
April 29, 2025	76,177

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. Restricted stock unit awards granted to members of the Board generally vest on the first anniversary of the grant date. The Company accrues for estimated forfeitures in share-based compensation by an annual factor of 3%. For forfeited awards, in the period of occurrence, the reduction in expense is booked as an incremental reduction to share-based compensation. For non-forfeited awards, in the final period of expense, the incremental remaining expense is recognized.

A summary of the status of restricted stock unit grants and changes during the years ended December 31, 2025, 2024 and 2023 is as follows:

	2025		2024		2023	
	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	3,817,128	$ 1.70	3,148,226	$ 2.40	2,623,790	$ 2.29
Granted	3,767,550	1.30	2,867,570	1.34	2,270,842	2.22
Forfeited or rescinded	(269,876)	1.37	(510,351)	1.61	(66,174)	2.22
Vested	(2,402,692)	1.73	(1,688,317)	2.43	(1,680,232)	1.99
Outstanding at end of year	4,912,110	$ 1.40	3,817,128	$ 1.70	3,148,226	$ 2.40

As of December 31, 2025, the Company had $2,462,658 of unrecognized compensation cost related to restricted stock unit grants that will be recognized over a weighted average period of 1.77 years.

During 2025, 2024, and 2023, 2,402,692, 1,688,317, and 1,680,232 restricted stock units vested, respectively. At the dates of vesting those restricted stock units had an aggregate intrinsic value of $3,047,762, $2,439,773, and $3,203,568, respectively.

Performance Stock Units - In accordance with the 2021 Plan, upon Board approval, the Company entered into performance stock unit (“PSU”) agreements (the “PSU Agreement”) with certain employees. The PSUs are performance-based restricted stock units subject to the terms of the 2021 Plan and the PSU Agreement.

On November 22, 2021, the Company granted a total of 860,216 PSUs 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 a total of 860,216 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 ended on December 31, 2024. In July 2024, two of the executive officers separated from the Company, forfeiting 215,054 of these PSUs. Based on the achievement of the performance goals for the 2022 PSU Awards, a total of 571,324 PSUs vested on December 31, 2024.

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 ended on December 31, 2025. In July 2024, two of the aforementioned executive officers separated from the Company, forfeiting 270,270 of these PSUs. In September 2025, one of the aforementioned executive officers separated from the Company, and accelerated the vesting of 135,135 of these PSUs. Based on the achievement of the performance goals for the 2023 PSU Awards, a total of 680,665 PSUs vested on December 31, 2025.

On April 30, 2024, the Company granted a total of 1,378,378 PSUs to the Company's five executive officers (the "2024 PSU Awards"). The performance period for the 2024 PSU Awards began on January 1, 2024, and will end on December 31, 2026. In July 2024, two of the aforementioned executive officers separated from the Company, forfeiting 378,378 of these PSUs. In September 2025, one of the aforementioned executive officers separated from the Company, and accelerated the vesting of 189,189 of these PSUs.

On April 29, 2025, the Company granted a total of 1,624,756 PSUs to the Company's six executive officers (the "2025 PSU Awards"). The performance period for the 2025 PSU Awards began on January 1, 2025, and will end on December 31, 2027. In September 2025, one of the aforementioned executive officers separated from the Company, and accelerated the vesting of 225,576 of these PSUs.

A summary of the status of the PSU awards and changes during the years ended December 31, 2025, 2024 and 2023 are as follows:

	2025		2024		2023	
	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**
Outstanding at beginning of year	1,891,892	$ 2.47	2,022,378	$ 3.11	1,720,432	$ 3.76
Granted	1,624,756	0.93	1,378,378	2.27	1,162,162	2.71
Incremental performance stock units vested	188,962	—	248,742	—	309,808	—
Forfeited, cancelled or rescinded	(265,054)	3.20	(1,186,282)	2.38	—	—
Vested	(1,230,565)	2.13	(571,324)	2.79	(1,170,024)	3.66
Outstanding at end of year	2,209,991	$ 1.42	1,891,892	$ 2.47	2,022,378	$ 3.11

The Company accrues for estimated forfeitures in share-based compensation by an annual factor of 3%. For forfeited awards, in the period of occurrence, the reduction in expense is booked as an incremental reduction to share-based compensation. For non-forfeited awards, in the final period of expense, the incremental remaining expense is recognized.

As of December 31, 2025, the Company had $1,599,139 of unrecognized compensation cost related to the PSU Awards that will be recognized over a weighted average period of 1.53 years.

During 2025, 1,230,565 PSUs vested. At the dates of vesting those PSUs had an aggregate intrinsic value of $1,175,073.

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, 2025, 2024, and 2023:

	2025	2024	2023
Employer safe harbor match	$ 509,967	$ 455,641	$ 346,268

NOTE 13 — COMMITMENTS AND CONTINGENCIES

Surety Bonds – As of December 31, 2025 and 2024, the Company had $2,275,000 in total surety bonds. A Texas Railroad Commission ("RRC") required blanket performance bond to operate 100 or more wells in the State of Texas in the amount of $250,000 and another RRC required blanket plugging extension bond in the amount of $2,000,000. Both RRC bonds have zero collateral requirements A surety bond in the amount of $25,000 to operate wells in the State of New Mexico was also in place as of December 31, 2025 and 2024; however, that bond will likely be released as the Company no longer operates wells in New Mexico. Total expenses related to the RRC surety bonds were $38,000 and $29,585 for the years ended December 31, 2025 and 2024, respectively. The New Mexico bond is supported by a $25,000 standby letter of credit collateralized by the Credit Facility with the bank.

Standby Letters of Credit – As of December 31, 2025 and 2024, the Company had total standby letters of credit outstanding of $35,000, consisting of a $10,000 standby letter of credit in favor of a federal agency and a $25,000 standby letter of credit issued to support bonding requirements related to the Company's former operations in the State of New Mexico. The Company no longer conducts operations in New Mexico and expects the standby letter of credit related to the New Mexico bonding requirements to be released, subject to regulatory approval. No amounts had been drawn under either standby letter of credit as of December 31, 2025 and 2024, and no liability has been recorded in the accompanying Balance Sheets related to these arrangements.

NOTE 14 — INCOME TAXES

For the years ended December 31, 2025, 2024, and 2023, components of our provision (benefit) for income taxes are as follows.

Provision for (Benefit from) Income Taxes:	2025	2024	2023
Federal deferred tax	$ (7,654,389)	$ 19,096,010	$ (901,522)
State current tax	374,982	401,197	72,213
State deferred tax	(173,339)	943,747	954,551
Provision for (Benefit from) Income Taxes	$ (7,452,746)	$ 20,440,954	$ 125,242

The Company's overall effective tax rates are calculated as Benefit from (Provision for) Income Taxes divided by Income (Loss) Before Benefit from (Provision for) Income Taxes. The effective tax rates for the years ended December 31, 2025, 2024, and 2023 were as follows.

	For the years ended December 31,		
	2025	2024	2023
Effective tax rate [1]	17.7 %	23.3 %	0.1 %

[1] The effective tax rates for the years ended December 31, 2025 and 2024 differ from the U.S. federal statutory rate of 21% primarily due to share-based and executive compensation and state income taxes. The effective tax rate for the year ended December 31, 2023 was 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.

The following is a reconciliation of the difference between the effective income tax rate and the U.S. federal statutory rate, for the year ended December 31, 2025.

Rate Reconciliation:	2025	
	Amount	Percent
Pre-tax book income (loss)	$ (42,183,945)	
Tax provision (benefit) computed at the U.S. federal statutory rate	(8,858,628)	21.0 %
State and local income tax, net of federal income tax effect [1]	174,193	(0.4)
Nontaxable or nondeductible items:		
Share-based compensation and executive compensation disallowance	1,209,928	(2.9)
Meals and entertainment	20,147	0.0
Other	1,614	0.0
Provision for (Benefit from) Income Taxes	$ (7,452,746)	17.7 %

[1] State taxes in Texas made up the majority (greater than 50%) of the tax effect in this category.

As previously disclosed for the years ended December 31, 2024, and 2023, prior to the adoption of ASU 2023-09, the following is a reconciliation of the difference between the effective income tax rate and the U.S. federal statutory rate.

Rate Reconciliation:	2024	2023
Pre-tax book income (loss) [2]	$ 87,911,268	$ 104,917,670
Tax at federal statutory rate	18,461,366	22,032,711
Excess tax benefit from stock option exercises and restricted stock vesting	104,344	478,304
Adjust prior estimates to tax return	69,654	(474,617)
States taxes, net of federal benefit	1,008,096	1,122,782
Valuation allowance	—	(24,182,975)
Non-deductible expenses and other	797,494	1,149,037
Provision for (Benefit from) Income Taxes	$ 20,440,954	$ 125,242

[2] Amount in the year ended December 31, 2023 represented 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, 2025 and 2024.

	2025	2024
Deferred Tax Assets		
Net operating loss (NOL) carryforward	$ 72,880,353	$ 68,516,720
Share-based compensation	910,213	1,097,273
Asset retirement obligation	6,627,813	5,755,174
§163(j) business interest expense carryforward	19,675,692	18,838,600
Other	1,488,392	1,672,268
Gross Deferred Tax Assets	$ 101,582,463	$ 95,880,035
Less: valuation allowance	—	—
Net Deferred Tax Assets	$ 101,582,463	$ 95,880,035
Deferred Tax Liabilities		
Property and equipment	$ (115,663,637)	$ (123,318,803)
Fair value of derivative instruments	(6,107,910)	(392,761)
Other	(575,035)	(760,273)
Net Deferred Tax Liabilities	$ (122,346,582)	$ (124,471,837)
Net Deferred Tax Liability	$ (20,764,119)	$ (28,591,802)

The following table summarizes income taxes paid (net of refunds received) for the year ended December 31, 2025. All jurisdictions in which income taxes paid (net of refunds received) were equal to or greater than five percent of total income taxes paid (net of refunds received) are included below (if the noted jurisdiction did not meet the five percent threshold for a particular year, the amount for that year is not included below).

Income taxes paid (net of refunds received)	2025
Federal income taxes	$ —
State and local income taxes:	
Texas	$ 337,787
Other	9,700
Total state and local income taxes, net of refunds	$ 347,487
Total income taxes paid, net of refunds received	$ 347,487

As of December 31, 2025, the Company had net operating loss carryforwards for federal income tax reporting purposes of approximately $96.9 million which, if unused, will begin to expire in 2033 and fully expire in 2037 and an additional $248.2 million that can be carried forward indefinitely.

Section 382 of the Internal Revenue Code of 1986, as amended, 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, 2025, we carried a valuation allowance against our federal and state deferred tax assets of $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. 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. This, coupled with the income tax provision for the year ended December 31, 2025 resulted in an ending federal net deferred tax liability of $16,977,823. Additionally, the Company reported a net state deferred tax liability at December 31, 2025 of $3,786,296 attributable to certain state deferred tax liabilities mainly associated with property and equipment.

NOTE 15 — SEGMENT REPORTING

In accordance with ASU 2023-07 "*Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*," the Company has performed an assessment of its reporting to comply with the new requirements for the fiscal year beginning January 1, 2024 and for interim periods beginning January 1, 2025. The Company's operations consist of the exploration, production, and sale of oil, natural gas, and NGLs, primarily within the Permian Basin of Texas, and is regulated by the RRC. The Company operates different areas within the Permian Basin, including the Northwest Shelf and Central Basin Platform.

The Company's operations and financials are managed by one cohesive group of individuals, identified as the chief operating decision maker ("CODM"), consisting of the Chairman of the Board and Chief Executive Officer; Executive Vice President and Chief Operations Officer; Executive Vice President and Chief Exploration Officer; Senior Vice President of Operations; and Vice President and Interim Chief Financial Officer. The CODM group reviews the Company's operating results, including condensed financial statements on a monthly basis for evaluating performance and determining resource allocation. The significant expense categories provided to the CODM include lease operating expenses; gathering, transportation and processing costs; ad valorem taxes; and oil and natural gas production taxes. Each of these costs are deducted from oil, natural gas, and natural gas liquids revenues by operating segment to arrive at operating segment profit, used to assess performance.

The Company assessed whether its operating segments exhibited similar economic characteristics and whether its operating segments had a similar nature of products, services, production processes, purchaser types/classes, product distribution, and regulatory environment. Each operating segment has similar products (oil, natural gas, and NGLs), similar production processes, similar types of purchasers (midstream companies, or companies with midstream components), similar methods of product delivery, and is governed by the same regulations. After a thorough analysis of each of these factors with regards to the Company's operating segments, it has been determined that it is appropriate to aggregate its operating segments into a single reportable segment, Exploration and Production, which includes all of its revenues, lease operating expenses, gathering, transportation and processing costs, ad valorem taxes, and oil and natural gas production taxes. Refer to the table below.

	For the years ended December 31,		
	2025	2024	2023
Exploration and Production			
Oil, natural gas, and natural gas liquids revenues [1]	$ 307,178,072	$ 366,327,414	$ 361,056,001
Lease operating expenses [2]	(79,353,806)	(78,310,949)	(70,158,227)
Gathering, transportation and processing costs	(585,087)	(506,333)	(457,573)
Ad valorem taxes	(7,906,586)	(8,069,064)	(6,757,841)
Oil and natural gas production taxes	(14,312,232)	(16,116,565)	(18,135,336)
Exploration and Production segment profit	**$ 205,020,361**	**$ 263,324,503**	**$ 265,547,024**

(1) All of the Company's revenues are within the Permian Basin within the United States.

(2) The CODM also reviews the following cost categories within lease operating expenses. Refer to the following table.

	For the years ended December 31,		
	2025	2024	2023
Lease operating expenses:			
Workovers	$ 12,025,118	$ 15,150,944	$ 14,919,560
Other lease operating expenses	$ 67,328,688	$ 63,160,005	$ 55,238,667
Total lease operating expenses	**$ 79,353,806**	**$ 78,310,949**	**$ 70,158,227**

The following tables include a reconciliation of the total reportable segments' measures of profit or loss to the Company's total income (loss) before income taxes. Additionally included is a reconciliation between the reportable segments' assets to the Company's total assets.

	For the year ended December 31, 2025		
	Exploration and Production	Corporate	Total Company
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 307,178,072	$ —	$ 307,178,072
Lease operating expenses	(79,353,806)	—	(79,353,806)
Gathering, transportation and processing costs	(585,087)	—	(585,087)
Ad valorem taxes	(7,906,586)	—	(7,906,586)
Oil and natural gas production taxes	(14,312,232)	—	(14,312,232)
Depreciation, depletion and amortization [3]	—	(96,414,150)	(96,414,150)
Ceiling test impairment [3]	—	(108,825,446)	(108,825,446)
Asset retirement obligation accretion	—	(1,490,255)	(1,490,255)
Operating lease expense	—	(700,362)	(700,362)
General and administrative expense	—	(31,928,576)	(31,928,576)
Interest income	—	290,879	290,879
Interest (expense)	—	(40,430,929)	(40,430,929)
Gain (loss) on derivative contracts	—	31,658,839	31,658,839
Gain (loss) on disposal of assets	—	446,400	446,400
Other income	—	189,294	189,294
Income (Loss) Before Benefit from (Provision for) Income Taxes	**$ 205,020,361**	**$ (247,204,306)**	**$ (42,183,945)**
Total Assets [3]	**$ 1,365,252,029**	**$ 46,647,220**	**$ 1,411,899,249**
Capital expenditures	**$ 98,211,527**	**$ —**	**$ 98,211,527**

[3] All of the Company's assets are located within the United States. As the CODM does not view depreciation, depletion and amortization or ceiling test impairment as a significant Exploration and Production segment expense, the Company has included this expense within the Corporate column of the reconciliation table.

	For the year ended December 31, 2024		
	Exploration and Production	Corporate	Total Company
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 366,327,414	$ —	$ 366,327,414
Lease operating expenses	(78,310,949)	—	(78,310,949)
Gathering, transportation and processing costs	(506,333)	—	(506,333)
Ad valorem taxes	(8,069,064)	—	(8,069,064)
Oil and natural gas production taxes	(16,116,565)	—	(16,116,565)
Depreciation, depletion and amortization [3]	—	(98,702,843)	(98,702,843)
Ceiling test impairment [3]	—	—	—
Asset retirement obligation accretion	—	(1,380,298)	(1,380,298)
Operating lease expense	—	(700,362)	(700,362)
General and administrative expense	—	(29,640,300)	(29,640,300)
Interest income	—	491,946	491,946
Interest (expense)	—	(43,311,810)	(43,311,810)
Gain (loss) on derivative contracts	—	(2,365,917)	(2,365,917)
Gain (loss) on disposal of assets	—	89,693	89,693
Other income	—	106,656	106,656
Income (Loss) Before Benefit from (Provision for) Income Taxes	**$ 263,324,503**	**$ (175,413,235)**	**$ 87,911,268**
Total Assets [3]	**$ 1,381,583,504**	**$ 26,515,970**	**$ 1,408,099,474**
Capital expenditures	**$ 151,946,171**	**$ —**	**$ 151,946,171**

[3] All of the Company's assets are located within the United States. As the CODM does not view depreciation, depletion and amortization or ceiling test impairment as a significant Exploration and Production segment expense, the Company has included this expense within the Corporate column of the reconciliation table.

	For the year ended December 31, 2023		
	Exploration and Production	Corporate	Total Company
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 361,056,001	$ —	$ 361,056,001
Lease operating expenses	(70,158,227)	—	(70,158,227)
Gathering, transportation and processing costs	(457,573)	—	(457,573)
Ad valorem taxes	(6,757,841)	—	(6,757,841)
Oil and natural gas production taxes	(18,135,336)	—	(18,135,336)
Depreciation, depletion and amortization [3]	—	(88,610,291)	(88,610,291)
Ceiling test impairment [3]	—	—	—
Asset retirement obligation accretion	—	(1,425,686)	(1,425,686)
Operating lease expense	—	(541,801)	(541,801)
General and administrative expense	—	(29,188,755)	(29,188,755)
Interest income	—	257,155	257,155
Interest (expense)	—	(43,926,732)	(43,926,732)
Gain (loss) on derivative contracts	—	2,767,162	2,767,162
Gain (loss) on disposal of assets	—	(87,128)	(87,128)
Other income	—	198,935	198,935
Income (Loss) Before Benefit from (Provision for) Income Taxes	**$ 265,547,024**	**$ (160,557,141)**	**$ 104,989,883**
Total Assets [3]	**$ 1,338,584,701**	**$ 37,911,691**	**$ 1,376,496,392**
Capital expenditures	**$ 151,969,735**	**$ —**	**$ 151,969,735**

[3] All of the Company's assets are located within the United States. As the CODM does not view depreciation, depletion and amortization or ceiling test impairment as a significant Exploration and Production segment expense, the Company has included this expense within the Corporate column of the reconciliation table.

The following table discloses the purchasers from which 10% or more of revenues were derived in the years noted.

	For the years ended December 31,		
	2025	2024	2023
Purchasers with 10% or more percentage of total revenue [4]			
Phillips 66 Company ("Phillips")	67%	61%	66%
Concord Energy LLC	13%	14%	*
LPC Crude III, LLC	*	13%	*
NGL Crude Partners ("NGL Crude")	*	10%	10%
Enterprise Crude Oil LLC ("Enterprise")	*	*	12%

[4] All the Company's purchasers are within the Exploration and Production operating segment.

* Represents less than 10%

NOTE 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 concluded discovery in the matter and are currently set for trial in the second quarter of 2026.

NOTE 17 — SUBSEQUENT EVENTS

In accordance with ASC Topic 855, Subsequent Events, the Company has evaluated all events subsequent to the balance sheet date of December 31, 2025, through the date these condensed financial statements were issued, March 4, 2026. The Company did not have any material subsequent events to report.

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,	**2025**	**2024**	**2023**
Oil, natural gas, and natural gas liquids sales	$ 307,178,072	$ 366,327,414	$ 361,056,001
Lease operating expenses	(79,353,806)	(78,310,949)	(70,158,227)
Gathering, transportation and processing costs	(585,087)	(506,333)	(457,573)
Ad valorem taxes	(7,906,586)	(8,069,064)	(6,757,841)
Production taxes	(14,312,232)	(16,116,565)	(18,135,336)
Depreciation, depletion, and amortization	(96,414,150)	(98,702,843)	(88,610,291)
Ceiling test impairment	(108,825,446)	—	—
General and administrative (exclusive of corporate overhead)	(4,162,391)	(3,360,370)	(2,839,401)
Income tax benefit (expense)	774,233	(37,493,250)	(208,917)
Results of Oil and Natural Gas Producing Operations	$ (3,607,393)	$ 123,768,040	$ 173,888,415

Costs Incurred in Oil and Gas Producing Activities

For the years ended December 31,	**2025**	**2024**	**2023**
Payments to acquire oil and natural gas properties	$ 84,392,361	$ 2,210,826	$ 82,900,900
Payments to explore oil and natural gas properties	—	—	—
Payments to develop oil and natural gas properties	95,207,027	153,945,456	152,559,314
Total costs incurred	$ 179,599,388	$ 156,156,282	$ 235,460,214

Capitalized Costs

As of December 31,	**2025**	**2024**	**2023**
Oil and natural gas properties, full cost method			
Proved properties	$ 1,891,510,431	$ 1,809,309,848	$ 1,663,548,249
Unproved properties	—	—	—
Total oil and natural gas properties, full cost method	$ 1,891,510,431	$ 1,809,309,848	$ 1,663,548,249
Accumulated depletion of oil and natural gas properties	(564,169,311)	(469,786,336)	(373,280,583)
Net oil and natural gas properties capitalized	$ 1,327,341,120	$ 1,339,523,512	$ 1,290,267,666

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, 2025, 2024 and 2023 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, 2025, 2024 and 2023 are based on the respective 12-month unweighted average of the first of the month prices of the WTI posted prices which equates to $61.82 per barrel, $71.96 per barrel and $74.70 per barrel, respectively. The natural gas prices as of December 31, 2025, 2024 and 2023 are based on the respective 12-month unweighted average of the first of month prices of the Henry Hub spot price which equates to $3.387 per MMBtu, $2.130 per MMBtu and $2.637 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, natural gas, and NGLs 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,	2025			
	Oil (Bbl)	Gas (Mcf)	Natural Gas Liquids (Bbl)	Boe[1]
Proved Developed and Undeveloped Reserves				
Beginning of year	80,904,071	149,817,162	28,303,085	134,176,684
Purchase of minerals in place	9,915,483	10,067,543	2,373,336	13,966,743
Extensions, discoveries and improved recovery	7,281,553	10,624,783	2,133,786	11,186,136
Sales of minerals in place	—	—	—	—
Production	(4,841,164)	(6,980,958)	(1,387,818)	(7,392,476)
Revisions of previous quantity estimates [2]	(2,939,895)	12,652,046	2,171,955	1,340,734
End of year	90,320,048	176,180,576	33,594,344	153,277,821
Proved Developed at beginning of year	56,106,714	102,538,111	19,426,387	92,622,787
Proved Undeveloped at beginning of year	24,797,357	47,279,051	8,876,698	41,553,897
Proved Developed at end of year	60,108,129	121,424,006	23,453,484	103,798,946
Proved Undeveloped at end of year	30,211,919	54,756,570	10,140,860	49,478,875

(1) Six Mcf is deemed the equivalent of one Boe.
(2) Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history, a rule that undeveloped reserves must be drilled within five years of originally being booked, and/or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

Notable changes in proved reserves for the year ended December 31, 2025 included the following:

- *Extensions.* In 2025, extensions of 11.2 MMBoe were primarily the result of 41 newly added PUDs in addition to an active leasing program. Also impacting extensions were three successfully drilled wells in the Northwest Shelf and Central Basin Platform.

- *Purchase of minerals in place.* In 2025, the Company completed the acquisition of Lime Rock oil and gas leases and related property within Andrews County, as well as a few other minor acquisitions, that resulted in 14.0 MMBoe of additional reserves.

- *Sales of minerals in place.* In 2025, the Company did not sell any reserves.

- *Revision of previous quantity estimates.* In 2025, the positive revisions of prior reserves of 1.3 MMBoe consisted of a positive 7.2 MMBoe related to changes in performance and other economic factors, offset by a negative 5.9 MMBoe related to changes in price (including differentials and gathering related contract change that effects differentials).

For the year ended December 31,	2024			
	Oil (Bbl)	**Gas (Mcf)**	**Natural Gas Liquids (Bbl)**	**Boe(1)**
Proved Developed and Undeveloped Reserves				
Beginning of year	82,141,277	146,396,322	23,218,564	129,759,229
Purchase of minerals in place	—	—	—	—
Extensions, discoveries and improved recovery	11,495,236	10,630,769	2,738,451	16,005,482
Sales of minerals in place	(1,140,568)	(56,020)	(16,361)	(1,166,266)
Production	(4,861,628)	(6,423,674)	(1,258,814)	(7,191,054)
Revisions of previous quantity estimates (2)	(6,730,246)	(730,235)	3,621,245	(3,230,707)
End of year	80,904,071	149,817,162	28,303,085	134,176,684
Proved Developed at beginning of year	56,029,039	99,896,022	15,449,907	88,128,284
Proved Undeveloped at beginning of year	26,112,238	46,500,300	7,768,657	41,630,945
Proved Developed at end of year	56,106,714	102,538,111	19,426,387	92,622,787
Proved Undeveloped at end of year	24,797,357	47,279,051	8,876,698	41,553,897

(1) Six Mcf is deemed the equivalent of one Boe.
(2) Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history, a rule that undeveloped reserves must be drilled within five years of originally being booked, and/or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

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

- *Extensions.* In 2024, extensions of 16.0 MMBoe were primarily the result of the successful operated drilling program in the Northwest Shelf and Central Basin Platform.
- *Purchase of minerals in place.* In 2024, the Company did not purchase any additional reserves.
- *Sales of minerals in place.* In 2024, the Company sold 1.2 MMBoe from the divestiture of certain oil and gas properties, including vertical wells and associated facilities, within the Central Basin Platform in Andrews and Gaines Counties.
- *Revision of previous quantity estimates.* In 2024, the negative revisions of prior reserves of 3.2 MMBoe consisted of a positive 0.2 MMBoe related to changes in price (including differentials and gathering related contract change that effects differentials), offset by a negative 3.4 MMBoe related to changes in performance and other economic factors.

For the year ended December 31,	2023			
	Oil (Bbl)	**Gas (Mcf)**	**Natural Gas Liquids (Bbl)**	**Boe[1]**
Proved Developed and Undeveloped Reserves				
Beginning of year	88,704,743	157,870,449	23,105,658	138,122,143
Purchase of minerals in place	6,543,640	3,372,965	1,089,382	8,195,183
Extensions, discoveries and improved recovery	3,098,845	4,113,480	1,014,343	4,798,768
Sales of minerals in place	(4,897,921)	(2,674,955)	(392,953)	(5,736,700)
Production	(4,579,942)	(6,339,158)	(976,852)	(6,613,320)
Revisions of previous quantity estimates [2]	(6,728,088)	(9,946,459)	(621,014)	(9,006,845)
End of year	82,141,277	146,396,322	23,218,564	129,759,229
Proved Developed at beginning of year	57,012,137	106,399,050	15,332,804	90,078,116
Proved Undeveloped at beginning of year	31,692,606	51,471,399	7,772,854	48,044,027
Proved Developed at end of year	56,029,039	99,896,022	15,449,907	88,128,284
Proved Undeveloped at end of year	26,112,238	46,500,300	7,768,657	41,630,945

(1) Six Mcf is deemed the equivalent of one Boe.
(2) Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history, a rule that undeveloped reserves must be drilled within five years of originally being booked, and/or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

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

- *Extensions.* In 2023, extensions of 4.8 MMBoe were primarily the result of the successful operated drilling program and non-operated activity in the Northwest Shelf and Central Basin Platform.

- *Purchase of minerals in place.* In 2023, the Company completed the acquisition of 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 Company sold 5.7 MMBoe from the divestiture of 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 quantity estimates.* In 2023, the negative revisions of prior reserves of 9.0 MMBoe consisted of 5.3 MMBoe (59%) related to changes in price and 3.7 MMBoe (41%) related to changes in performance and 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

As of December 31,	2025	2024	2023
Future cash inflows	$ 5,976,599,552	$ 6,165,487,616	$ 6,622,410,752
Future production costs	(2,473,482,048)	(2,432,555,200)	(2,413,303,488)
Future development costs [(1)]	(573,423,296)	(536,825,664)	(562,063,424)
Future income taxes	(402,808,797)	(465,768,645)	(548,664,988)
Future net cash flows	2,526,885,411	2,730,338,107	3,098,378,852
10% annual discount for estimated timing of cash flows	(1,403,392,079)	(1,497,401,764)	(1,699,193,661)
Standardized Measure of Discounted Future Net Cash Flows	$ 1,123,493,332	$ 1,232,936,343	$ 1,399,185,191

(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, 2025:

Changes in Standardized Measure of Discounted Future Net Cash Flows

	2025	2024	2023
Beginning of the year	$ 1,232,936,343	$ 1,399,185,191	$ 2,272,113,518
Purchase of minerals in place	174,287,315	—	141,738,066
Extensions, discoveries and improved recovery	98,831,276	226,741,618	57,607,609
Development costs incurred during the year	28,098,777	71,665,321	70,697,664
Sales of oil and gas produced, net of production costs	(205,605,448)	(263,830,836)	(266,004,598)
Sales of minerals in place	—	(10,230,951)	(59,600,128)
Accretion of discount	146,282,714	164,703,142	277,365,650
Net changes in price and production costs	(372,012,158)	(285,618,955)	(1,181,594,019)
Net change in estimated future development costs	28,456,200	6,732,428	37,865,811
Revisions of previous quantity estimates	17,046,040	(50,292,499)	(187,443,783)
Changes in estimated timing of cash flows	(60,003,723)	(44,073,556)	(17,257,348)
Net change in income taxes	35,175,996	17,955,440	253,696,749
End of the Year	$ 1,123,493,332	$ 1,232,936,343	$ 1,399,185,191

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

6500 RIVER PLACE BLVD, SUITE 3-200
AUSTIN, TEXAS 78730-1111
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817- 336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

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, 2025, December 31, 2024, and December 31, 2023, in Ring Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2025, to references to our report dated January 22, 2026, 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, 2025 (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, 2025. 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, 333-237988, 333-267599, 333-283978, and 333-286646) and Form S-8 (Nos. 333-191485, 333-257633, 333-277796, and 333-287784).

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

J. Zane Meekins, P. E.
Executive Vice President

Fort Worth, Texas
March 4, 2026

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our reports dated March 4, 2026, 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, 2025. 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, File No. 333-267599, File No. 333-283978, and File No. 333-286646) and Forms S-8 (File No. 333-191485, File No. 333-257633, File No. 333-277796 and File No. 333-287784).

/s/ GRANT THORNTON LLP

Houston, Texas
March 4, 2026

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 4, 2026

/s/ Paul D. McKinney
Paul D. McKinney, CEO
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, Rocky P. Kwon, 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 4, 2026

/s/ Rocky P. Kwon
Rocky P. Kwon, Vice President and CAO
(Principal Financial Officer and Principal Accounting 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, 2025, 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 4, 2026

/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, 2025, 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 4, 2026

/s/ Rocky P. Kwon
Rocky P. Kwon
Vice President and CAO
(Principal Financial Officer and Principal Accounting 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.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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January 22, 2026

Mr. Alex Dyes
Chief Operating Officer & EVP
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 December 31, 2025

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 December 31, 2025. 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 January 22, 2026, 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 Developed Producing	Proved Developed Non-Producing	Proved Undeveloped	Total Proved
Net Reserves					
Oil/Condensate	-- Mbbl	51,983.1	8,125.0	30,211.9	90,320.0
Gas	-- MMcf	86,678.5	34,745.5	54,756.6	176,180.6
NGL	-- Mbbl	18,294.4	5,159.1	10,140.9	33,594.3
Revenue					
Oil/Condensate	-- M$	3,342,124.3	520,889.0	1,932,054.8	5,795,068.4
Gas	-- M$	-59,369.4	16,723.1	15,492.4	-27,153.9
NGL	-- M$	104,810.8	31,786.9	72,088.0	208,685.6
Severance and Ad Valorem Taxes	-- M$	223,913.5	35,763.4	130,315.6	389,992.5
Operating Expenses	-- M$	1,259,433.6	216,925.9	607,130.6	2,083,489.8
Investments	-- M$	66,196.0	68,734.9	438,492.4	573,423.3
Operating Income (BFIT)	-- M$	1,838,022.4	247,974.8	843,696.6	2,929,692.9
Discounted @ 10%	-- M$	**901,093.8**	**105,584.0**	**311,530.7**	**1,318,208.1**

The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

As requested, hydrocarbon pricing of $3.387 per MMBtu of gas (Henry Hub spot) and $61.82 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 price for the previous 12 months. As directed, this 12-month period ends in December 2025. 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 $64.16 per barrel of oil, -$0.15 per Mcf of gas, and $6.21 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 $48,755,200 is modelled in twenty-two cases scheduled over the next 50 years. The PUD cases have an average gross cost of $47,700 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.

Our work-papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

J. Zane Meekins, P.E.
Executive Vice President

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *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. 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. 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. 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. 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.

APPENDIX

Reserve Definitions and Classifications

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

"(i) The area of 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) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

"(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

"(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

"(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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

"(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

"(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"(31) **Undeveloped oil and gas reserves**. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

"(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

"(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

"(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.

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

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

"(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

"(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

"(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

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

"(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

"(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

"(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

"(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

"(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

"(vi) Pursuant to paragraph (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**. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"Note to paragraph (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)."