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

Form 10-Q

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

For the quarterly period ended June 30, 2025

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

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

As of August 6, 2025, the registrant had outstanding 206,544,770 shares of common stock ($0.001 par value).

TABLE OF CONTENTS

Forward Looking Statements

This Quarterly Report on Form 10-Q (herein, “Quarterly 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 Quarterly 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 Quarterly 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 Quarterly Report. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly 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 of wells, 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 and potential full-cost ceiling impairment;
- 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 environmental, social and governance ("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;
- the short and long-term potential impact to us of worsening trade relations and related economic disruptions including, but not limited to, inflation, energy price volatility, tariffs, trade wars, and supply chain disruptions;
- 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 our Annual Report on Form 10-K for the year ended December 31, 2024, as well as in our condensed financial statements, related notes, and the other financial information appearing elsewhere in this Quarterly 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 Quarterly Report to “Ring,” “Ring Energy,” the “Company,” “we,” “us,” “our” or “ours” refer to Ring Energy, Inc.

PART I — FINANCIAL INFORMATION

Item 1. Condensed Financial Statements

The following (a) condensed balance sheet as of December 31, 2024 which has been derived from our audited financial statements, and (b) the unaudited condensed financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). Accordingly, certain disclosures by accounting principles generally accepted in the United States ("GAAP") and normally included in Annual Reports on Form 10-K have been omitted. Although management believes that our disclosures are adequate to make the information presented not misleading, these unaudited interim condensed financial statements should be read in conjunction with the Company's audited financial statements and related notes included in its most recent Annual Report on Form 10-K.

RING ENERGY, INC.
CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2025	December 31, 2024
ASSETS		
Current Assets		
Cash and cash equivalents	$ —	$ 1,866,395
Accounts receivable	38,729,543	36,172,316
Joint interest billing receivables, net	781,362	1,083,164
Derivative assets	14,815,235	5,497,057
Inventory	5,384,553	4,047,819
Prepaid expenses and other assets	2,716,824	1,781,341
Total Current Assets	62,427,517	50,448,092
Properties and Equipment		
Oil and natural gas properties, full cost method	1,949,768,881	1,809,309,848
Financing lease asset subject to depreciation	3,712,233	4,634,556
Fixed assets subject to depreciation	3,494,678	3,389,907
Total Properties and Equipment	1,956,975,792	1,817,334,311
Accumulated depreciation, depletion and amortization	(521,741,945)	(475,212,325)
Net Properties and Equipment	1,435,233,847	1,342,121,986
Operating lease asset	1,599,335	1,906,264
Derivative assets	6,613,480	5,473,375
Deferred financing costs	10,456,692	8,149,757
Total Assets	$ 1,516,330,871	$ 1,408,099,474
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 82,422,634	$ 95,729,261
Income tax liability	675,352	328,985
Financing lease liability	724,527	906,119
Operating lease liability	674,927	648,204
Derivative liabilities	2,322,147	6,410,547
Notes payable	1,488,419	496,397
Deferred cash payment	9,604,736	—
Asset retirement obligations	414,974	517,674
Total Current Liabilities	98,327,716	105,037,187
Non-current Liabilities		
Deferred income taxes	37,456,550	28,591,802
Revolving line of credit	448,000,000	385,000,000
Financing lease liability, less current portion	580,604	647,078
Operating lease liability, less current portion	1,061,124	1,405,837
Derivative liabilities	3,864,413	2,912,745
Asset retirement obligations	29,144,695	25,864,843
Total Liabilities	618,435,102	549,459,492
Commitments and contingencies (See Note 12)		
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; 206,542,615 shares and 198,561,378 shares issued and outstanding, respectively	206,542	198,561
Additional paid-in capital	809,921,900	800,419,719
Retained earnings (Accumulated deficit)	87,767,327	58,021,702
Total Stockholders' Equity	897,895,769	858,639,982
Total Liabilities and Stockholders' Equity	$ 1,516,330,871	$ 1,408,099,474

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

RING ENERGY, INC.
CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 82,602,759	$ 99,139,349	$ 161,693,966	$ 193,642,485
Costs and Operating Expenses				
Lease operating expenses	20,245,981	19,309,017	39,923,533	37,669,451
Gathering, transportation and processing costs	133,809	107,629	337,421	273,683
Ad valorem taxes	1,648,647	1,337,276	3,180,755	3,482,907
Oil and natural gas production taxes	3,832,607	3,627,264	7,417,062	8,055,567
Depreciation, depletion and amortization	25,569,914	24,699,421	48,185,897	48,491,871
Asset retirement obligation accretion	382,251	352,184	708,800	703,018
Operating lease expense	175,090	175,090	350,181	350,181
General and administrative expense	7,138,519	7,713,534	15,758,495	15,182,756
Total Costs and Operating Expenses	59,126,818	57,321,415	115,862,144	114,209,434
Income from Operations	23,475,941	41,817,934	45,831,822	79,433,051
Other Income (Expense)				
Interest income	69,658	144,933	159,716	223,477
Interest (expense)	(11,757,404)	(10,946,127)	(21,256,190)	(22,445,071)
Gain (loss) on derivative contracts	14,648,054	(1,828,599)	13,719,264	(20,843,094)
Gain (loss) on disposal of assets	155,293	51,338	279,903	89,693
Other income	150,770	—	159,712	25,686
Net Other Income (Expense)	3,266,371	(12,578,455)	(6,937,595)	(42,949,309)
Income Before Provision for Income Taxes	26,742,312	29,239,479	38,894,227	36,483,742
Provision for Income Taxes	(6,107,425)	(6,820,485)	(9,148,602)	(8,549,371)
Net Income	$ 20,634,887	$ 22,418,994	$ 29,745,625	$ 27,934,371
Basic Earnings per Share	$ 0.10	$ 0.11	$ 0.15	$ 0.14
Diluted Earnings per Share	$ 0.10	$ 0.11	$ 0.15	$ 0.14

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

RING ENERGY, INC.
CONDENSED STATEMENT OF STOCKHOLDERS' EQUITY
(Unaudited)

For the Six Months Ended June 30, 2025	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity
Balance, December 31, 2024	198,561,378	$ 198,561	$ 800,419,719	$ 58,021,702	$ 858,639,982
Restricted stock vested	1,983,465	1,983	(1,983)	—	—
Shares to cover tax withholdings for restricted stock vested	(488,596)	(488)	488	—	—
Payments to cover tax withholdings for restricted stock vested, net	—	—	(896,431)	—	(896,431)
Common stock issuance for Lime Rock Acquisition	6,452,879	6,453	7,414,358	—	7,420,811
Share-based compensation	—	—	1,690,958	—	1,690,958
Net income	—	—	—	9,110,738	9,110,738
Balance, March 31, 2025	206,509,126	$ 206,509	$ 808,627,109	$ 67,132,440	$ 875,966,058
Restricted stock vested	41,834	42	(42)	—	—
Shares to cover tax withholdings for restricted stock vested	(8,345)	(9)	9	—	—
Payments to cover tax withholdings for restricted stock vested, net	—	—	(57,015)	—	(57,015)
Share-based compensation	—	—	1,351,839	—	1,351,839
Net income	—	—	—	20,634,887	20,634,887
Balance, June 30, 2025	206,542,615	$ 206,542	$ 809,921,900	$ 87,767,327	$ 897,895,769
For the Six Months Ended June 30, 2024					
Balance, December 31, 2023	196,837,001	$ 196,837	$ 795,834,675	$ (9,448,612)	$ 786,582,900
Restricted stock vested	1,342,112	1,342	(1,342)	—	—
Shares to cover tax withholdings for restricted stock vested	(244,911)	(245)	245	—	—
Payments to cover tax withholdings for restricted stock vested, net	—	—	(814,985)	—	(814,985)
Share-based compensation	—	—	1,723,832	—	1,723,832
Net income	—	—	—	5,515,377	5,515,377
Balance, March 31, 2024	197,934,202	$ 197,934	$ 796,742,425	$ (3,933,235)	$ 793,007,124
Restricted stock vested	303,797	304	(304)	—	—
Shares to cover tax withholdings for restricted stock vested	(71,702)	(72)	72	—	—
Payments to cover tax withholdings for restricted stock vested, net	—	—	(86,991)	—	(86,991)
Share-based compensation	—	—	2,077,778	—	2,077,778
Net income	—	—	—	22,418,994	22,418,994
Balance, June 30, 2024	198,166,297	$ 198,166	$ 798,732,980	$ 18,485,759	$ 817,416,905

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

RING ENERGY, INC.
CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	For the Six Months Ended	
	June 30, 2025	June 30, 2024
Cash Flows From Operating Activities		
Net income	$ 29,745,625	$ 27,934,371
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	48,185,897	48,491,871
Asset retirement obligation accretion	708,800	703,018
Amortization of deferred financing costs	3,074,667	2,443,215
Share-based compensation	3,042,797	3,801,610
Credit loss expense	18,122	178,777
(Gain) loss on disposal of assets	(279,903)	(89,693)
Deferred income tax expense (benefit)	8,755,985	8,206,573
Excess tax expense (benefit) related to share-based compensation	108,763	87,780
(Gain) loss on derivative contracts	(13,719,264)	20,843,094
Cash received (paid) for derivative settlements, net	124,249	(4,056,012)
Changes in operating assets and liabilities:		
Accounts receivable	(2,373,460)	(2,284,512)
Inventory	(1,336,734)	360,537
Prepaid expenses and other assets	(935,483)	(747,575)
Accounts payable	(12,880,531)	(9,313,631)
Settlement of asset retirement obligation	(571,271)	(752,324)
Net Cash Provided by Operating Activities	61,668,259	95,807,099
Cash Flows From Investing Activities		
Payments for the Lime Rock Acquisition	(70,859,769)	—
Payments to purchase oil and natural gas properties	(797,289)	(622,862)
Payments to develop oil and natural gas properties	(49,256,881)	(75,459,527)
Payments to acquire or improve fixed assets subject to depreciation	(169,661)	(151,586)
Proceeds from sale of fixed assets subject to depreciation	17,360	10,605
Proceeds from sale of New Mexico properties	—	(144,398)
Insurance proceeds received for damage to oil and natural gas properties	99,913	—
Net Cash Used in Investing Activities	(120,966,327)	(76,367,768)
Cash Flows From Financing Activities		
Proceeds from revolving line of credit	170,322,997	81,000,000
Payments on revolving line of credit	(107,322,997)	(99,000,000)
Payments for taxes withheld on vested restricted shares, net	(953,446)	(901,976)
Proceeds from notes payable	1,648,539	1,501,507
Payments on notes payable	(656,517)	(679,446)
Payment of deferred financing costs	(5,381,602)	(45,704)
Reduction of financing lease liabilities	(225,301)	(431,284)
Net Cash Provided by (Used in) Financing Activities	57,431,673	(18,556,903)
Net Increase (Decrease) in Cash	(1,866,395)	882,428
Cash at Beginning of Period	1,866,395	296,384
Cash at End of Period	$ —	$ 1,178,812

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

	For the Six Months Ended	
	June 30, 2025	June 30, 2024
Supplemental Cash Flow Information		
Cash paid for interest	$ 20,958,502	$ 20,229,215
Cash paid (refunded) for income taxes	(62,513)	72,213
Noncash Investing and Financing Activities		
Asset retirement obligation incurred during development	$ 23,158	$ 323,673
Asset retirement obligation acquired	2,587,179	—
Asset retirement obligation sold	—	(256,740)
Financing lease assets obtained in exchange for new financing lease liability, net (1)	264,114	341,218
Change in capitalized expenditures attributable to drilling projects financed through current liabilities	(781,392)	(4,461,783)
Lime Rock Acquisition Supplemental Schedule		
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	2,294,105	—
Cash paid for fixed assets acquired	(34,275)	—
Payments for the Lime Rock Acquisition	$ 70,859,769	$ —
Investing Activities - Noncash		
Assumption of suspense liability	$ 561,977	$ —
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	$ —

(1) Included within the financing lease assets obtained in exchange for new financing lease liability, net is $95,845 of finance lease asset terminations for the six months ended June 30, 2025. For the six months ended June 30, 2024, the Company had $45,436 in finance lease asset terminations.

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

RING ENERGY, INC.
NOTES TO CONDENSED FINANCIAL STATEMENTS
(UNAUDITED)

Index to the Notes to the Condensed Financial Statements

NOTE 1 — BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Condensed Financial Statements – The accompanying condensed financial statements prepared by Ring Energy, Inc., a Nevada corporation (the “Company,” "Ring Energy," “Ring,” "we," "us," or "our"), have not been audited by an independent registered public accounting firm. In the opinion of the Company’s management, the accompanying unaudited condensed financial statements contain all adjustments necessary for fair presentation of the results of operations for the periods presented, which adjustments were of a normal recurring nature, except as disclosed herein. The condensed results of operations for the three and six months ended June 30, 2025 are not necessarily indicative of the results to be expected for the full year ending December 31, 2025, for various reasons, including the impact of fluctuations in prices received for oil and natural gas, natural production declines, the uncertainty of exploration and development drilling results, fluctuations in the fair value of derivative instruments, and other factors.

These unaudited condensed financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) applicable to interim financial information, and, accordingly, do not include all of the information and notes required by GAAP for complete financial statements. Therefore, these condensed financial statements should be read in conjunction with the financial statements and notes included in the Company’s annual report on Form 10-K for the year ended December 31, 2024.

Organization and Nature of Operations – Ring Energy 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 in 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 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 unaudited condensed 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 $0 and $1,616,395 as of June 30, 2025 and December 31, 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. During the six months ended June 30, 2025, sales to three purchasers represented 66%, 13% and 9%, respectively, of total oil, natural gas, and natural gas liquids sales. As of June 30, 2025, receivables outstanding from these three purchasers represented 73%, 10% and 7%, respectively, of accounts receivable. The following table reflects the Company's beginning and ending balances of our account receivables from purchasers of our oil and gas for the three and six months ended June 30, 2025 and June 30, 2024.

	For the Three Months Ended	
	June 30, 2025	June 30, 2024
Beginning balance of accounts receivable from purchasers of oil and gas	$ 35,111,264	$ 34,415,464
Ending balance of accounts receivable from purchasers of oil and gas	36,251,914	38,478,082

	For the Six Months Ended	
	June 30, 2025	June 30, 2024
Beginning balance of accounts receivable from purchasers of oil and gas	$ 33,774,968	$ 37,879,779
Ending balance of accounts receivable from purchasers of oil and gas	36,251,914	38,478,082

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 June 30, 2025 or December 31, 2024.

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 three and six months ended June 30, 2025 and June 30, 2024.

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Credit loss expense	$ 205	$ 14,937	$ 18,122	$ 178,777

The following table reflects the Company's joint interest billing receivables and allowance for credit losses as of June 30, 2025 and December 31, 2024.

	June 30, 2025	December 31, 2024
Joint interest billing receivables	$ 981,217	$ 1,264,897
Allowance for credit losses	(199,855)	(181,733)
Joint interest billing receivables, net	$ 781,362	$ 1,083,164

The increase of $18,122 in the allowance for credit losses during the six months ended June 30, 2025 was for owner settlements considered uncollectible with no offsetting revenues held in suspense.

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 June 30, 2025 and December 31, 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 three and six months ended June 30, 2025 and 2024.

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Depletion	$ 25,224,638	$ 24,325,186	$ 47,479,214	$ 47,754,798
Depletion rate, per barrel-of-oil-equivalent (Boe)	$ 13.02	$ 13.51	$ 13.21	$ 13.52

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.

No impairments on oil and natural gas properties as a result of the ceiling test were recorded for the three and six months ended June 30, 2025 and 2024.

Land, Buildings, Equipment, Software, Leasehold Improvements, Automobiles, Buildings and Structures – Land, buildings, equipment, software, leasehold improvements, automobiles, buildings and structures 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, equipment, software, leasehold improvements, automobiles, buildings and structures and placing them in service. Upon sale or abandonment, the cost of the fixed asset(s) and related accumulated depreciation are removed from the accounts and any gain or loss is recognized.

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

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

The following table provides information on the Company's depreciation expense for the three and six months ended June 30, 2025 and 2024.

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Depreciation	$ 106,658	$ 102,772	$ 203,278	$ 204,709

Notes Payable – 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 2025, 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 $1,648,539. The APR for this note was 7.75%. As of June 30, 2025 and

December 31, 2024, the notes payable balances included in current liabilities on the Condensed Balance Sheets were $1,488,419 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 three and six months ended June 30, 2025 and 2024.

	Three Months Ended		Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Weighted average notes payable balance	$ 330,644	$ 335,293	$ 316,501	$ 330,272
Weighted average interest rate on weighted average notes payable	12.88 %	11.91 %	10.85 %	9.91 %

The following table shows interest paid related to notes payable for the three and six months ended June 30, 2025 and 2024. This interest is included within "Interest (expense)" in the Condensed Statements of Operations.

	Three Months Ended		Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Interest paid for notes payable	$ 10,645	$ 9,986	$ 17,166	$ 16,366

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

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 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 June 30, 2025 and December 31, 2024, the Company did not carry a valuation allowance against its federal and state deferred tax assets.

The Company recorded the following federal and state income tax benefits (provisions) for the three and six months ended June 30, 2025 and 2024.

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Deferred federal income tax provision	$ (5,776,325)	$ (6,427,828)	$ (8,592,403)	$ (7,979,587)
Current state income tax provision	(147,461)	(152,385)	(283,854)	(255,018)
Deferred state income tax provision	(183,639)	(240,272)	(272,345)	(314,766)
Provision for Income Taxes	$ (6,107,425)	$ (6,820,485)	$ (9,148,602)	$ (8,549,371)
Effective tax rate [(1)]	22.84%	23.33%	23.52%	23.43%

(1) The Company's overall effective tax rate is calculated as Provision for Income Taxes divided by Income Before Provision for Income Taxes. The effective tax rates for the three and six months ended June 30, 2025 and 2024 were higher than the federal statutory corporate tax rate, primarily impacted by the state income taxes.

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, 2020 and after remain subject to examination. The Company's federal income tax returns for the years ended December 31, 2008 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 2019 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 Condensed Statements of Operations.

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

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

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 11 — EMPLOYEE STOCK OPTIONS AND RESTRICTED STOCK UNITS". 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 Condensed Statements of Operations, incurred for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended		Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Share-based compensation	$ 1,351,839	$ 2,077,778	$ 3,042,797	$ 3,801,610

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 Condensed 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. See "NOTE 6 — DERIVATIVE FINANCIAL INSTRUMENTS" for additional information.

The Company uses the indirect method of reporting operating cash flows within the Condensed 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 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 condensed 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 will include the applicable enhanced disclosures 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 condensed 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). The amendments in this update are effective for annual reporting periods beginning after December 15, 2026 and interim reporting periods with 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.

NOTE 2 — REVENUE RECOGNITION

The Company predominantly derives its revenue from the sale of produced crude oil, natural gas, and natural gas liquids ("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 ASC 606-10-50-14A, 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 Company's natural gas sales processing contracts for its Central Basin Platform properties and a portion of its Northwest Shelf assets, the Company delivers unprocessed natural gas to a midstream processing entity at the wellhead. The midstream processing entity obtains control of the natural gas and NGLs at the wellhead. The midstream processing entity gathers and processes the natural gas and NGLs and remits proceeds to the Company for the resulting sale of natural gas and NGLs. Under these processing agreements, the Company recognizes revenue when control transfers to the purchaser at the point of delivery and it is probable the Company will collect the consideration it is entitled to receive. As such, the Company accounts for any fees and deductions as a reduction of the transaction price.

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

Disaggregation of revenue – The following table presents revenues disaggregated by product:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Oil, Natural Gas, and Natural Gas Liquids Revenues				
Oil	$ 82,778,476	$ 99,289,498	$ 159,283,526	$ 191,584,083
Natural gas [1]	(2,238,937)	(2,972,807)	(2,541,664)	(3,791,042)
Natural gas liquids	2,063,220	2,822,658	4,952,104	5,849,444
Total oil, natural gas, and natural gas liquids revenues	$ 82,602,759	$ 99,139,349	$ 161,693,966	$ 193,642,485

[1] In the three and six months ended June 30, 2025 and 2024, the Company experienced a net negative total gas revenue, due to a lower gross realized sales prices per Mcf compared with the plant fees per Mcf.

NOTE 3 — LEASES

The Company has operating leases for its offices in Midland, Texas and The Woodlands, Texas. The Midland office was originally under a five-year lease which began January 1, 2021. The Midland office lease was amended effective October 1, 2022, with the revised five-year lease ending September 30, 2027. Beginning January 15, 2021, the Company entered into a five-and-a-half-year sub-lease for office space in The Woodlands, Texas; however, effective as of May 31, 2023, The Woodlands office sub-lease was terminated. On May 9, 2023, the Company entered into a 71-month (five years and 11-month) new lease for a larger amount of office space in The Woodlands, Texas. The 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 June 30, 2025 are as follows:

	2025	2026	2027	2028	2029	Other Future Years	Total
Operating lease payments [1]	$ 366,218	$ 636,649	$ 460,497	$ 250,606	$ 149,628	$ —	$ 1,863,598
Financing lease payments [2]	433,416	664,994	282,147	24,213	—	—	1,404,770

(1) The weighted average annual discount rate as of June 30, 2025 for operating leases was 4.50%. Based on this rate, the future lease payments above include imputed interest of $127,547. The weighted average remaining term of operating leases was 3.05 years.

(2) The weighted average annual discount rate as of June 30, 2025 for financing leases was 7.50%. Based on this rate, the future lease payments above include imputed interest of $99,639. The weighted average remaining term of financing leases was 1.90 years.

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

	As of	
	June 30, 2025	**December 31, 2024**
Operating lease liability, current portion	$ 674,927	$ 648,204
Operating lease liability, non-current portion	1,061,124	1,405,837
Operating lease liability, total	**$ 1,736,051**	**$ 2,054,041**
Total undiscounted future cash flows (sum of future operating lease payments)	1,863,598	2,224,840
Imputed interest	127,547	170,799
Undiscounted future cash flows less imputed interest	**$ 1,736,051**	**$ 2,054,041**
Financing lease liability, current portion	$ 724,527	$ 906,119
Financing lease liability, non-current portion	580,604	647,078
Financing lease liability, total	**$ 1,305,131**	**$ 1,553,197**
Total undiscounted future cash flows (sum of future financing lease payments)	1,404,770	1,667,763
Imputed interest	99,639	114,566
Undiscounted future cash flows less imputed interest	**$ 1,305,131**	**$ 1,553,197**

The following table provides supplemental information regarding lease costs in the Condensed Statements of Operations:

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	**June 30, 2024**	**June 30, 2025**	**June 30, 2024**
Operating lease costs	$ 175,090	$ 175,090	$ 350,181	$ 350,181
Short-term lease costs [(1)]	1,260,098	1,104,057	2,412,402	2,085,348
Financing lease costs:				
Amortization of financing lease assets [(2)]	238,618	271,463	503,405	532,364
Interest on financing lease liabilities [(3)]	27,638	31,422	56,379	62,739

(1) Amount included in Lease operating expenses
(2) Amount included in Depreciation, depletion and amortization
(3) Amount included in Interest (expense)

NOTE 4 — EARNINGS PER SHARE INFORMATION

The following table presents the calculation of the Company's basic and diluted earnings per share for the three and six months ended June 30, 2025 and 2024. For all dilutive securities, the treasury stock method of calculating the incremental shares is applied.

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Net Income	$ 20,634,887	$ 22,418,994	$ 29,745,625	$ 27,934,371
Basic Weighted-Average Shares Outstanding	206,522,356	197,976,721	202,964,856	197,684,638
Effect of dilutive securities:				
Stock options	—	—	—	—
Restricted stock units	341,611	1,872,895	852,082	1,477,377
Performance stock units	113,760	534,997	250,931	643,290
Common warrants	4,600	44,200	17,338	40,207
Diluted Weighted-Average Shares Outstanding	206,982,327	200,428,813	204,085,207	199,845,512
Basic Earnings per Share	$ 0.10	$ 0.11	$ 0.15	$ 0.14
Diluted Earnings per Share	$ 0.10	$ 0.11	$ 0.15	$ 0.14

The following table presents the securities which were excluded from the Company's computation of diluted earnings per share for the three and six months ended June 30, 2025 and 2024, as their effect would have been anti-dilutive.

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Antidilutive securities:				
Stock options to purchase common stock	65,500	65,500	65,500	67,533
Unvested restricted stock units	3,745,348	57,363	2,598,851	28,681
Unvested performance stock units	2,570,776	1,520,194	1,000,000	1,050,636

NOTE 5 — ACQUISITIONS AND DIVESTITURES

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 $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.

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”). Pursuant to the closing of the Purchase Agreement, on March 31, 2025 the Company acquired (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, for a purchase price (the “Purchase Price”) of (i) a cash deposit of $5.0 million paid on February 26, 2025 into a third-party escrow account as a deposit pursuant to the Purchase Agreement, (ii) approximately $63.6 million in cash paid on the closing date, net of approximately $12.7 million of preliminary and customary purchase price adjustments and subject to final post-closing settlement between the Company and Lime Rock with an effective date of October 1, 2024, (iii) an aggregate of 6,452,879 shares of common stock and (iv) a deferred cash payment of $10.0 million to be paid by December 31, 2025.

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 preliminary allocation of the total cost of the Lime Rock Acquisition to the assets acquired and liabilities assumed as of the Lime Rock Acquisition date:

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
Total cash consideration	$	78,015,005
Direct transaction costs		2,294,105
Total consideration	**$**	**87,729,921**
Fair value of assets acquired:		
Oil and natural gas properties	$	90,844,802
Fixed assets		34,275
Amount attributable to assets acquired	$	90,879,077
Fair value of liabilities assumed:		
Suspense liability	$	561,977
Asset retirement obligations		2,587,179
Amount attributable to liabilities assumed	$	3,149,156
Net assets acquired	**$**	**87,729,921**

NOTE 6 — 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 ("West Texas Intermediate") 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 Condensed Balance Sheets.

The Company's derivative financial instruments are recorded at fair value and included as either assets or liabilities in the accompanying Condensed 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 Condensed Statements of Operations.

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

	As of	
	June 30, 2025	December 31, 2024
Commodity derivative instruments, marked to market:		
Derivatives assets, current	**$ 14,815,235**	**$ 5,497,057**
Derivative assets, noncurrent	**$ 6,613,480**	**$ 5,473,375**
Derivative liabilities, current	**$ 2,322,147**	**$ 6,410,547**
Derivative liabilities, noncurrent	**$ 3,864,413**	**$ 2,912,745**

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

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Oil derivatives:				
Realized gain (loss) on oil derivatives	$ 433,301	$ (4,073,127)	$ (206,966)	$ (6,812,097)
Unrealized gain (loss) on oil derivatives	12,145,940	2,308,594	14,487,365	(14,685,728)
Gain (loss) on oil derivatives	$ 12,579,241	$ (1,764,533)	$ 14,280,399	$ (21,497,825)
Natural gas derivatives:				
Realized gain (loss) on natural gas derivatives	244,542	1,478,630	$ 331,215	$ 2,756,085
Unrealized gain (loss) on natural gas derivatives	1,824,271	(1,542,696)	(892,350)	(2,101,354)
Gain (loss) on natural gas derivatives	$ 2,068,813	$ (64,066)	$ (561,135)	$ 654,731
Gain (loss) on derivative contracts	**$ 14,648,054**	**$ (1,828,599)**	**$ 13,719,264**	**$ (20,843,094)**

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

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Cash flows from operating activities				
Cash received (paid) for oil derivatives	$ 433,301	$ (4,073,127)	$ (206,966)	$ (6,812,097)
Cash received (paid) for natural gas derivatives	244,542	1,478,630	331,215	2,756,085
Cash received (paid) for derivative settlements, net	**$ 677,843**	**$ (2,594,497)**	**$ 124,249**	**$ (4,056,012)**

The following tables reflect the details of current derivative contracts as of June 30, 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)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
Swaps:								
Hedged volume (Bbl)	471,917	241,755	608,350	577,101	171,400	529,000	509,500	492,000
Weighted average swap price	$ 68.64	$ 65.56	$ 67.95	$ 67.41	$ 62.26	$ 65.34	$ 62.82	$ 60.45
Two-way collars:								
Hedged volume (Bbl)	225,400	404,800	—	—	379,685	—	—	—
Weighted average put price	$ 65.00	$ 60.00	$ —	$ —	$ 60.00	$ —	$ —	$ —
Weighted average call price	$ 78.91	$ 75.68	$ —	$ —	$ 72.50	$ —	$ —	$ —

	Gas Hedges (Henry Hub)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
NYMEX Swaps:								
Hedged volume (MMBtu)	300,500	128,400	140,600	662,300	121,400	613,300	—	—
Weighted average swap price	$ 3.88	$ 4.25	$ 4.20	$ 3.54	$ 4.22	$ 3.83	$ —	$ —
Two-way collars:								
Hedged volume (MMBtu)	309,350	748,000	694,500	139,000	648,728	128,000	717,000	694,000
Weighted average put price	$ 3.17	$ 3.10	$ 3.50	$ 3.50	$ 3.10	$ 3.50	$ 3.99	$ 3.00
Weighted average call price	$ 4.98	$ 4.40	$ 5.11	$ 5.42	$ 4.24	$ 5.42	$ 5.21	$ 4.32

	Oil Hedges (basis differential)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
Argus basis swaps:								
Hedged volume (Bbl)	183,000	276,000	—	—	—	—	—	—
Weighted average spread price (1)	$ 1.00	$ 1.00	$ —	$ —	$ —	$ —	$ —	$ —

	Gas Hedges (basis differential)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
El Paso Permian Basin basis swaps:								
Hedged volume (MMBtu)	381,725	363,200	—	—	—	—	700,000	—
Weighted average spread price (2)	$ 1.69	$ 1.69	$ —	$ —	$ —	$ —	$ 0.74	$ —

(1) The oil basis swap hedges are calculated as the fixed price (weighted average spread price above) less the difference between WTI Midland and WTI Cushing, in the issue of Argus Americas Crude.

(2) 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 7 — 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 6 — 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 June 30, 2025				
Commodity Derivatives - Assets	$ —	$ 21,428,715	$ —	$ 21,428,715
Commodity Derivatives - Liabilities	$ —	$ (6,186,560)	$ —	$ (6,186,560)
Total	$ —	$ 15,242,155	$ —	$ 15,242,155

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 8 — 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 be (i) 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 June 30, 2025, $448 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 June 30, 2025, the Company's unused line of credit was approximately $137.0 million, which was calculated by subtracting the outstanding Credit Facility balance of $448 million and standby letters of credit of $35,000 ($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 9 — 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 for the asset retirement obligation during the six months ended June 30, 2025 is as follows:

Balance, December 31, 2024	$	26,382,517
Liabilities acquired		2,587,179
Liabilities incurred		23,158
Liabilities settled		(141,985)
Accretion expense		708,800
Balance, June 30, 2025	$	29,559,669

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

	June 30, 2025		December 31, 2024	
Asset retirement obligations, current	$	414,974	$	517,674
Asset retirement obligations, non-current		29,144,695		25,864,843
Asset retirement obligations	$	29,559,669	$	26,382,517

NOTE 10 — STOCKHOLDERS' EQUITY

As of December 31, 2024, the Company had 78,200 exercisable common warrants outstanding, with a contractual exercise price of $0.80 per warrant, expiring five years from initial issuance in October 2020. During the six months ended June 30, 2025 and 2024, no common warrants were exercised. The following table reflects the common warrants exercised, including the proceeds received for such exercises. As of June 30, 2025, there remained 78,200 exercisable common warrants.

	Common Warrants	Exercise Price		Proceeds Received	
Exercisable, December 31, 2023	78,200	$	0.80		
Exercised	—		—	$	—
Exercisable, March 31, 2024	78,200	$	0.80		
Exercised	—		—	$	—
Exercisable, June 30, 2024	78,200	$	0.80		
Exercisable, December 31, 2024	78,200	$	0.80		
Exercised	—		—	$	—
Exercisable, March 31, 2025	78,200	$	0.80		
Exercised	—		—	$	—
Exercisable, June 30, 2025	78,200	$	0.80		

NOTE 11 — EMPLOYEE STOCK OPTIONS AND RESTRICTED STOCK UNITS

Share-based compensation expense charged against income for share-based awards during the three and six months ended June 30, 2025 and 2024 was as follows. These amounts are included in General and administrative expense in the Condensed Statements of Operations.

	Three Months Ended		Six Months Ended	
	June 30, 2025	June 30, 2024	June 30, 2025	June 30, 2024
Share-based compensation expense from:				
Employee stock options	$ —	$ —	$ —	$ —
Restricted stock unit grants	1,022,645	996,381	2,269,974	2,128,078
Performance stock unit awards	329,194	1,081,397	772,823	1,673,532
Total share-based compensation	**$ 1,351,839**	**$ 2,077,778**	**$ 3,042,797**	**$ 3,801,610**

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 stockholders. There were no shares eligible for grant, either as stock options or as restricted stock, as of June 30, 2025.

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. There were 11,511,061 shares available for grant as of June 30, 2025 under the 2021 Plan.

Employee Stock Options

A summary of the status of the stock options as of June 30, 2025 and 2024 and changes during the respective six month periods then ended are as follows:

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding, December 31, 2023	70,500	$ 10.33		
Granted	—	—		
Forfeited	—	—		
Expired	(5,000)	5.50		
Exercised	—	—		
Outstanding, March 31, 2024	65,500	$ 10.70	2.31 years	$ —
Exercisable, March 31, 2024	65,500	$ 10.70	2.31 years	
Granted	—	—		
Forfeited	—	—		
Expired	—	—		
Exercised	—	—		
Outstanding, June 30, 2024	65,500	$ 10.70	2.06 years	$ —
Exercisable, June 30, 2024	65,500	$ 10.70	2.06 years	
Outstanding, December 31, 2024	65,500	$ 10.70		
Granted	—	—		
Forfeited	—	—		
Expired	—	—		
Exercised	—	—		
Outstanding, March 31, 2025	65,500	$ 10.70	1.31 years	$ —
Exercisable, March 31, 2025	65,500	$ 10.70	1.31 years	
Granted	—	—		
Forfeited	—	—		
Expired	—	—		
Exercised	—	—		
Outstanding, June 30, 2025	65,500	$ 10.70	1.06 years	$ —
Exercisable, June 30, 2025	65,500	$ 10.70	1.06 years	

The intrinsic values were calculated using the closing price on June 30, 2025 of $0.79 and the closing price on June 30, 2024 of $1.69. As of June 30, 2025, the Company had $0 of unrecognized compensation cost related to stock options.

Restricted Stock Units

A summary of the restricted stock unit ("RSU") activity as of June 30, 2025 and 2024, respectively, and changes during the respective six month periods then ended are as follows:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Outstanding, December 31, 2023	3,148,226	$ 2.40
Granted	2,647,970	1.30
Forfeited or rescinded	(26,802)	1.30
Vested	(1,342,112)	2.35
Outstanding, March 31, 2024	4,427,282	$ 1.77
Granted	60,000	2.04
Forfeited or rescinded	(66,101)	1.43
Vested	(303,797)	2.74
Outstanding, June 30, 2024	4,117,384	$ 1.70
Outstanding, December 31, 2024	3,817,128	$ 1.70
Granted	3,691,373	1.31
Forfeited or rescinded	—	—
Vested	(1,983,465)	1.75
Outstanding, March 31, 2025	5,525,036	$ 1.42
Granted	76,177	0.92
Forfeited or rescinded	(86,238)	1.31
Vested	(41,834)	2.12
Outstanding, June 30, 2025	5,473,141	$ 1.41

As of June 30, 2025, the Company had $4,763,815 of unrecognized compensation cost related to RSU grants that will be recognized over a weighted average period of 2.14 years. Grant activity for the six months ended June 30, 2025 was primarily RSU grants for the annual long-term incentive plan awards for employees. Grant activity for the three months ended June 30, 2025 was for a non-employee director.

Performance Stock Units

A summary of the status of the performance stock unit ("PSU") grants as of June 30, 2025 and 2024, respectively, along with changes during the respective six month periods then ended are as follows:

	Performance Stock Units	Weighted-Average Grant Date Fair Value
Outstanding, December 31, 2023	2,022,378	$ 3.11
Granted	—	—
Forfeited or rescinded	—	—
Vested	—	—
Outstanding, March 31, 2024	2,022,378	$ 3.11
Granted	1,378,378	$ 2.27
Forfeited or rescinded	—	$ —
Vested	—	$ —
Outstanding, June 30, 2024	3,400,756	$ 2.77
Outstanding, December 31, 2024	1,891,892	$ 2.47
Granted	—	—
Forfeited or rescinded	—	—
Vested	—	—
Outstanding, March 31, 2025	1,891,892	$ 2.47
Granted	1,624,756	$ 0.93
Forfeited or rescinded	—	$ —
Vested	—	$ —
Outstanding, June 30, 2025	3,516,648	$ 1.76

As of June 30, 2025, the Company had $3,263,646 of unrecognized compensation cost related to the PSU awards that will be recognized over a weighted average period of 1.66 years.

NOTE 12 — COMMITMENTS AND CONTINGENCIES

Standby Letters of Credit – A commercial bank previously issued standby letters of credit on behalf of the Company for $250,000 to the State of Texas, $10,000 to a federal agency, and $500,438 to an insurance company to secure the surety bonds described below. On February 23, 2024, the bank reduced the $500,438 standby letter of credit to $25,000 after approval of the insurance company, reduced the $250,000 standby letter of credit to the State of Texas to $0, and retained the standby letter of credit to the federal agency at $10,000. As of June 30, 2025, the Company had total standby letters of credit outstanding of $35,000. The standby letters of credit are valid until cancelled or matured and are collateralized by the Credit Facility with the bank. The terms of the letter of credit to the federal agency is extended for a term of one year at a time. The Company intends to renew the standby letter of credit to the federal agency for as long as required. Although the Company no longer operates any wells in the State of New Mexico, that standby letter of credit will need to be renewed until released. No amounts have been drawn under the standby letters of credit.

Surety Bonds – An insurance company issued surety bonds on behalf of the Company totaling $500,438 to various State of New Mexico agencies in order for the Company to do business in the State of New Mexico. The surety bonds are valid until canceled or matured. The terms of the surety bonds are extended for a term of one year at a time. As of June 30, 2025, the Company still had a surety bond in place of $25,000 for the State of New Mexico; however, these bonds are expected to be eliminated once change of ownership is approved by the New Mexico Oil Conservation Division. On January 10, 2024, two insurance companies issued surety bonds on behalf of the Company, one for $250,000, a Texas Railroad Commission ("RRC") required blanket performance bond to operate 100 wells or more in the State of Texas, and one for $2,000,000, an RRC required blanket plugging extension bond, each with zero collateral requirements. The term for these two surety bonds ends on July 1, 2026 and they can be renewed at that time. As of June 30, 2025, the Company had $2,275,000 in total surety bonds.

NOTE 13 — 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 Financial Officer; Executive Vice President and Chief Exploration Officer; and Senior Vice President of Operations. 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 Three Months Ended June 30,		For the Six Months Ended June 30,	
	2025	2024	2025	2024
Exploration and Production				
Oil, natural gas, and natural gas liquids revenues [1]	$ 82,602,759	$ 99,139,349	$ 161,693,966	$ 193,642,485
Lease operating expenses [2]	(20,245,981)	(19,309,017)	(39,923,533)	(37,669,451)
Gathering, transportation and processing costs	(133,809)	(107,629)	(337,421)	(273,683)
Ad valorem taxes	(1,648,647)	(1,337,276)	(3,180,755)	(3,482,907)
Oil and natural gas production taxes	(3,832,607)	(3,627,264)	(7,417,062)	(8,055,567)
Exploration and Production segment profit	**$ 56,741,715**	**$ 74,758,163**	**$ 110,835,195**	**$ 144,160,877**

[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 Three Months Ended June 30,		For the Six Months Ended June 30,	
	2025	2024	2025	2024
Lease operating expenses:				
Workovers	$ 3,173,838	$ 3,308,868	$ 5,990,047	$ 6,899,160
Other lease operating expenses	$ 17,072,143	$ 16,000,149	$ 33,933,486	$ 30,770,291
Total lease operating expenses	**$ 20,245,981**	**$ 19,309,017**	**$ 39,923,533**	**$ 37,669,451**

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

	For the three months ended June 30, 2025		
	Exploration and Production	Corporate	Total Company
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 82,602,759	$ —	$ 82,602,759
Lease operating expenses	(20,245,981)	—	(20,245,981)
Gathering, transportation and processing costs	(133,809)	—	(133,809)
Ad valorem taxes	(1,648,647)	—	(1,648,647)
Oil and natural gas production taxes	(3,832,607)	—	(3,832,607)
Depreciation, depletion and amortization [3]	—	(25,569,914)	(25,569,914)
Asset retirement obligation accretion	—	(382,251)	(382,251)
Operating lease expense	—	(175,090)	(175,090)
General and administrative expense	—	(7,138,519)	(7,138,519)
Interest income	—	69,658	69,658
Interest (expense)	—	(11,757,404)	(11,757,404)
Gain (loss) on derivative contracts	—	14,648,054	14,648,054
Gain (loss) on disposal of assets	—	155,293	155,293
Other income	—	150,770	150,770
Income Before Provision for Income Taxes	**$ 56,741,715**	**$ (29,999,403)**	**$ 26,742,312**
Total Assets [3]	**$ 1,479,364,319**	**$ 36,966,552**	**$ 1,516,330,871**
Capital expenditures	**$ 16,827,513**	**$ —**	**$ 16,827,513**

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

	For the three months ended June 30, 2024		
	Exploration and Production	Corporate	Total Company
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 99,139,349	$ —	$ 99,139,349
Lease operating expenses	(19,309,017)	—	(19,309,017)
Gathering, transportation and processing costs	(107,629)	—	(107,629)
Ad valorem taxes	(1,337,276)	—	(1,337,276)
Oil and natural gas production taxes	(3,627,264)	—	(3,627,264)
Depreciation, depletion and amortization [3]	—	(24,699,421)	(24,699,421)
Asset retirement obligation accretion	—	(352,184)	(352,184)
Operating lease expense	—	(175,090)	(175,090)
General and administrative expense	—	(7,713,534)	(7,713,534)
Interest income	—	144,933	144,933
Interest (expense)	—	(10,946,127)	(10,946,127)
Gain (loss) on derivative contracts	—	(1,828,599)	(1,828,599)
Gain (loss) on disposal of assets	—	51,338	51,338
Other income	—	—	—
Income Before Provision for Income Taxes	**$ 74,758,163**	**$ (45,518,684)**	**$ 29,239,479**
Total Assets [3]	**$ 1,365,645,578**	**$ 24,108,307**	**$ 1,389,753,885**
Capital expenditures	**$ 35,360,832**	**$ —**	**$ 35,360,832**

	For the Six months ended June 30, 2025		
	Exploration and Production	Corporate	Total Company
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 161,693,966	$ —	$ 161,693,966
Lease operating expenses	(39,923,533)	—	(39,923,533)
Gathering, transportation and processing costs	(337,421)	—	(337,421)
Ad valorem taxes	(3,180,755)	—	(3,180,755)
Oil and natural gas production taxes	(7,417,062)	—	(7,417,062)
Depreciation, depletion and amortization [3]	—	(48,185,897)	(48,185,897)
Asset retirement obligation accretion	—	(708,800)	(708,800)
Operating lease expense	—	(350,181)	(350,181)
General and administrative expense	—	(15,758,495)	(15,758,495)
Interest income	—	159,716	159,716
Interest (expense)	—	(21,256,190)	(21,256,190)
Gain (loss) on derivative contracts	—	13,719,264	13,719,264
Gain (loss) on disposal of assets	—	279,903	279,903
Other income	—	159,712	159,712
Income Before Provision for Income Taxes	**$ 110,835,195**	**$ (71,940,968)**	**$ 38,894,227**
Total Assets [3]	**$ 1,479,364,319**	**$ 36,966,552**	**$ 1,516,330,871**
Capital expenditures	**$ 49,279,044**	**$ —**	**$ 49,279,044**

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

	For the Six months ended June 30, 2024		
	Exploration and Production	Corporate	Total Company
Oil, Natural Gas, and Natural Gas Liquids Revenues	$ 193,642,485	$ —	$ 193,642,485
Lease operating expenses	(37,669,451)	—	(37,669,451)
Gathering, transportation and processing costs	(273,683)	—	(273,683)
Ad valorem taxes	(3,482,907)	—	(3,482,907)
Oil and natural gas production taxes	(8,055,567)	—	(8,055,567)
Depreciation, depletion and amortization (3)	—	(48,491,871)	(48,491,871)
Asset retirement obligation accretion	—	(703,018)	(703,018)
Operating lease expense	—	(350,181)	(350,181)
General and administrative expense	—	(15,182,756)	(15,182,756)
Interest income	—	223,477	223,477
Interest (expense)	—	(22,445,071)	(22,445,071)
Gain (loss) on derivative contracts	—	(20,843,094)	(20,843,094)
Gain (loss) on disposal of assets	—	89,693	89,693
Other income	—	25,686	25,686
Income Before Provision for Income Taxes	**$ 144,160,877**	**$ (107,677,135)**	**$ 36,483,742**
Total Assets (3)	**$ 1,365,645,578**	**$ 24,108,307**	**$ 1,389,753,885**
Capital expenditures	**$ 71,621,840**	**$ —**	**$ 71,621,840**

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2025	2024	2025	2024
Purchasers with 10% or more percentage of total revenue (4)				
Phillips 66 Company ("Phillips")	65%	62%	66%	61%
Concord Energy LLC	14%	14%	13%	13%
LPC Crude III, LLC	*	12%	*	12%
NGL Crude Partners ("NGL Crude")	*	10%	*	10%
Energy Transfer Crude Marketing	11%	*	*	*

(4) All the Company's purchasers are within the Exploration and Production operating segment.

* Represents less than 10%

NOTE 14 — SUBSEQUENT EVENTS

One Big Beautiful Bill Act – 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 do not anticipate these changes to have a material impact on our income tax provision. In accordance with ASC 740, the effect of a change in tax laws or rates is to be recognized at the date of enactment. As such, the impact of the OBBBA constitutes a non-recognized subsequent event.

Item 2: 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 condensed financial statements and the notes to those condensed financial statements included elsewhere in this Quarterly 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 Quarterly 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 in Texas. Our primary drilling operations target the oil and liquids rich producing formations in the Northwest Shelf and the Central Basin Platform, both of which are part of the Permian Basin.

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 stockholders.

- *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, 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.

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

- *Pursue strategic acquisitions with attractive upside potential.* Ring has a history of acquiring leasehold positions that it believes to have additional resource potential that meet its targeted returns on invested capital and comparable to its existing inventory of drilling locations. We pursue an acquisition strategy designed to increase reserves at attractive finding costs and complement existing core properties. Management intends to continue to pursue strategic acquisitions and structure the potential transactions financially, so they improve our balance sheet metrics and are accretive to stockholders. 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 purchase price (the "Purchase Price") of approximately $68.6 million in cash at closing (the "Closing Cash Consideration"), net of preliminary and customary purchase price adjustments and subject to final post-closing settlement between the Company and Lime Rock, $10.0 million due on or about December 31, 2025, and an aggregate of 6,452,879 shares of common stock of the Company, net of preliminary and customary purchase price adjustments. At the closing of the Lime Rock Acquisition, $5.0 million of the Closing Cash Consideration was retained in an escrow account to support Lime Rock's indemnity obligations under the Purchase 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%.

The table below sets forth our drilling and completion activities for the six months ended June 30, 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

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 to date continue 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. We anticipate a decrease in the twelve month average price over the next several months which will reasonably likely lead to a non-cash impairment. 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 such potential 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 that is connected to markets that are purchasing the natural gas produced. This has resulted in negative natural gas prices at times, whereby the seller is actually paying the purchaser to take the gas. We have experienced negative realized gas prices at times 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. In addition, the attempts to reduce inflation by the U.S. Federal Reserve have resulted in increased interest rates on debt. We continue to closely monitor costs and take all reasonable steps to mitigate the inflationary effect on our cost structure and also work to enhance our efficiency to minimize additional cost increases where possible.

Results of Operations

Oil, Natural Gas, and Natural Gas Liquids Revenues for the Three Months Ended June 30, 2025 and 2024

	For the Three Months Ended			
	June 30, 2025	June 30, 2024	Change	% Change
Net sales:				
Oil	$ 82,778,476	$ 99,289,498	$ (16,511,022)	(17) %
Natural gas	(2,238,937)	(2,972,807)	733,870	25 %
Natural gas liquids	2,063,220	2,822,658	(759,438)	(27) %
Total sales	**$ 82,602,759**	**$ 99,139,349**	**$ (16,536,590)**	**(17)%**
Net production:				
Oil (Bbls)	1,320,508	1,239,731	80,777	7 %
Natural gas (Mcf)	1,703,808	1,538,347	165,461	11 %
Natural gas liquids (Bbls)	333,374	304,448	28,926	10 %
Total production (Boe)(1)	**1,937,850**	**1,800,570**	**137,280**	**8 %**
Average sales price:				
Oil (per Bbl)	$ 62.69	$ 80.09	$ (17.40)	(22) %
Natural gas (per Mcf)	(1.31)	(1.93)	0.62	32 %
Natural gas liquids (Bbl)	6.19	9.27	(3.08)	(33) %
Total per Boe	**$ 42.63**	**$ 55.06**	**$ (12.43)**	**(23)%**

(1) Boe is calculated using six Mcf of natural gas as the equivalent of one barrel of oil.

Oil sales. Oil sales decreased approximately $16.5 million from $99.3 million to $82.8 million due to a price variance of $(23.0) million from a decrease in the average realized price per barrel from $80.09 to $62.69. This was offset by a volume variance of $6.5 million from an increase in sales volume from 1,239,731 barrels of oil to 1,320,508 barrels of oil. The increase in volume of 80,777 barrels of oil consisted of two components. An increase in volumes of 153,877 barrels was due to the wells acquired in the Lime Rock Acquisition (which closed at the end of March 2025), and a decrease of 73,100 was attributed to natural production declines from our legacy assets. The decreased average realized price per barrel was primarily a result of weaker market conditions.

Natural gas sales. Natural gas sales increased approximately $0.7 million from a negative $3.0 million to a negative $2.2 million, with a price variance of $1.1 million and with a volume variance making up the remaining difference. Our natural gas sales volumes increased from 1,538,347 Mcf to 1,703,808 Mcf, and the average realized price per Mcf increased from $(1.93) to $(1.31). Of the increase in volume of 165,461 Mcf, an increase of 98,282 Mcf was from the Lime Rock Acquisition and 67,179 Mcf was attributable to legacy assets. The price increase was driven by better market conditions. The realized revenue pricing included the impact of gas plant processing fees that were netted from revenue. For the three months ended June 30, 2025, gross revenues were $0.87 per Mcf and fees were $(2.18) per Mcf, compared to gross revenues of $(0.34) per Mcf and fees of $(1.59) per Mcf for the three months ended June 30, 2024. This resulted in a net realized price of $(1.31) per Mcf for the three months ended June 30, 2025 compared to $(1.93) per Mcf for the three months ended June 30, 2024.

Natural gas liquids sales. NGL sales decreased approximately $0.8 million from $2.8 million to $2.1 million. NGL sales volumes for the three months ended June 30, 2025 were 333,374 barrels of NGLs compared to 304,448 barrels of NGLs for the comparable period in 2024. Of the increase in volume of 28,926 barrels, 20,603 barrels were attributable to wells acquired and new wells drilled in the acreage acquired in the Lime Rock Acquisition, with the remaining 8,323 barrels attributable to our legacy assets due to increased NGL yields and increased gas production. The average realized price per barrel of NGLs was $6.19 for the three months ended June 30, 2025 compared to $9.27 for the three months ended June 30, 2024, due to weaker market conditions. Specifically, the gross realized price per NGL barrel was $19.02 and the average fees per barrel was $(12.83), resulting in a net realized price of $6.19 for the three months ended June 30, 2025, while the gross realized price per NGL barrel was $19.49 and the average fees per barrel was $(10.22), resulting in a net realized price of $9.27 for the same period in 2024.

Oil, Natural Gas, and Natural Gas Liquids Revenues for the Six Months Ended June 30, 2025 and 2024

	For the Six Months Ended			
	June 30, 2025	**June 30, 2024**	**Change**	**% Change**
Net sales:				
Oil	$ 159,283,526	$ 191,584,083	$ (32,300,557)	(17) %
Natural gas	(2,541,664)	(3,791,042)	1,249,378	33 %
Natural gas liquids	4,952,104	5,849,444	(897,340)	(15) %
Total sales	**$ 161,693,966**	**$ 193,642,485**	**$ (31,948,519)**	**(16)%**
Net production:				
Oil (Bbls)	2,407,202	2,458,568	(51,366)	(2) %
Natural gas (Mcf)	3,319,004	3,034,854	284,150	9 %
Natural gas liquids (Bbls)	632,740	568,250	64,490	11 %
Total production (Boe)[(1)]	**3,593,109**	**3,532,627**	**60,482**	**2 %**
Average sales price:				
Oil (per Bbl)	$ 66.17	$ 77.93	$ (11.76)	(15) %
Natural gas (per Mcf)	(0.77)	(1.25)	0.48	38 %
Natural gas liquids (Bbl)	7.83	10.29	(2.46)	(24) %
Total per Boe	**$ 45.00**	**$ 54.82**	**$ (9.82)**	**(18)%**

(1) Boe is calculated using six Mcf of natural gas as the equivalent of one barrel of oil.

Oil sales. Oil sales decreased approximately $32.3 million from $191.6 million to $159.3 million, with a price variance of $(28.3) million from a decrease in the average realized price per barrel from $77.93 to $66.17 as well as a volume variance of $(4.0) million due to a decrease in sales volume from 2,458,568 barrels of oil to 2,407,202 barrels of oil. The decrease in volume of 51,366 barrels consisted of two components. An increase in volumes of 153,877 was due to the Lime Rock Acquisition, and a decrease of 205,243 was attributed to natural production declines in the legacy assets. The Company's drilling and completion spend was 39% lower in the months that affected production for the first half of 2025 compared to the same months that affected production in the first half of 2024. This resulted in less offsets to declining production. The decreased average realized price per barrel was primarily the result of weaker market conditions.

Natural gas sales. Natural gas sales increased approximately $1.2 million from a negative $3.8 million to a negative $2.5 million, with a price variance of $1.6 million with a volume variance making up the remaining variance. The natural gas sales volume increased from 3,034,854 Mcf to 3,319,004 Mcf, and the average realized price per Mcf increased from $(1.25) to $(0.77). Of the increase in volume of 284,150 Mcf, an increase of 98,282 was due to the Lime Rock Acquisition, with the remaining increase of 185,868 from the legacy assets. The price increase was driven by more favorable market conditions. The realized revenue pricing includes the impact of gas plant processing fees that were netted from revenue. For the six months ended June 30, 2025, gross revenues were $1.35 per Mcf and fees were $(2.12) per Mcf, compared to gross revenues of $0.42 per Mcf and fees of $(1.67) per Mcf for the six months ended June 30, 2024. This resulted in a net realized price of $(0.77) for the six months ended June 30, 2025 compared to $(1.25) per Mcf for the six months ended June 30, 2024.

Natural gas liquids sales. NGL sales slightly decreased by approximately $0.8 million from $5.8 million to $5.0 million. NGL sales volumes for the six months ended June 30, 2025 were 632,740 barrels of NGLs compared to 568,250 barrels of NGLs for the comparable period in 2024. Of the increase in volume of 64,490 barrels, 20,603 was due to the Lime Rock Acquisition while the remaining 43,887 was from legacy assets. The average realized price per barrel of NGLs decreased by $2.46 to $7.83 for the six months ended June 30, 2025 compared to $10.29 for the six months ended June 30, 2024, attributable to weaker market conditions. Specifically, the gross realized price per NGL barrel was $20.74 and the average fees per barrel was $(12.91), resulting in a net realized price of $7.83 for the six months ended June 30, 2025, while the gross realized price per NGL barrel was $20.37 and the average fees per barrel was $(10.08), resulting in a net realized price of $10.29 for the same period in 2024.

Production Costs for the Three Months Ended June 30, 2025 and 2024

	For the Three Months Ended			
	June 30, 2025	**June 30, 2024**	**Change**	**% Change**
Lease operating expenses ("LOE")	**$ 20,245,981**	**$ 19,309,017**	**$ 936,964**	**5 %**
Average LOE per Boe	$ 10.45	$ 10.72	$ (0.27)	(3) %
Gathering, transportation and processing costs ("GTP")	**$ 133,809**	**$ 107,629**	**$ 26,180**	**24 %**
Average GTP per Boe	$ 0.07	$ 0.06	$ 0.01	17 %
Ad valorem taxes	**$ 1,648,647**	**$ 1,337,276**	**$ 311,371**	**23 %**
Average Ad valorem taxes per Boe	$ 0.85	$ 0.74	$ 0.11	15 %
Oil and natural gas production taxes	**$ 3,832,607**	**$ 3,627,264**	**$ 205,343**	**6 %**
Average Production taxes per Boe	$ 1.98	$ 2.01	$ (0.03)	(1) %
Production taxes as a percentage of total sales	4.64 %	3.66 %	0.98 %	27 %

Lease operating expenses. Our total lease operating expenses ("LOE") increased from $19.3 million to $20.2 million and decreased on a per Boe basis from $10.72 to $10.45. These per Boe amounts are calculated by dividing our total lease operating expenses by our total volume sold, in Boe. Total LOE increased primarily due to an 8% increase in production of 137,280 Boe as a result of the increased production and well count from the Lime Rock Acquisition as well as new wells drilled and completed in our development program. The primary cost driver for the period was an increase of $1.7 million in electricity costs. Other impacting factors included an increase of $0.1 million for environmental sustainability, offset by reductions of $0.5 million for supplies, tools, and materials, $0.1 million for workovers, $0.1 million for hot oil costs, and $0.1 million for chemical costs.

Gathering, transportation and processing costs. Our total gathering, transportation and processing costs ("GTP") increased from $107,629 to $133,809 and increased on a per Boe basis from $0.06 to $0.07. Beginning May 1, 2022, due to a natural gas processing entity taking control of transportation at the wellhead, GTP costs were re-classified as a reduction to oil and natural gas sales revenues. However, one contract remains in place with a natural gas processing entity where point of control of gas dictates requiring the fees be recorded as an expense. The increase in GTP costs was primarily due to the higher natural gas Mcf and NGL barrels processed.

Ad valorem taxes. Our total ad valorem taxes increased from $1.3 million to $1.6 million and increased on a per Boe basis from $0.74 to $0.85. Of the $0.3 million increase in ad valorem taxes, $0.6 million was related to Andrews County tax estimates, primarily related to the Lime Rock acquisition. There was also an increase of $0.1 million for Ector County tax estimates. These were offset by a reduction of $(0.4) million for Yoakum County tax estimates.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales were 3.66% for the three months ended June 30, 2024 and increased to 4.64% for the three months ended June 30, 2025. The tax in the three months ended June 30, 2024 included an accrual for refunds that had been filed with the state comptroller and therefore was less than the regular expected percentage of revenues.

Production Costs for the Six Months Ended June 30, 2025 and 2024

	For the Six Months Ended			
	June 30, 2025	**June 30, 2024**	**Change**	**% Change**
Lease operating expenses ("LOE")	**$ 39,923,533**	**$ 37,669,451**	**$ 2,254,082**	**6 %**
Average LOE per Boe	$ 11.11	$ 10.66	$ 0.45	4 %
Gathering, transportation and processing costs ("GTP")	**$ 337,421**	**$ 273,683**	**$ 63,738**	**23 %**
Average GTP per Boe	$ 0.09	$ 0.08	$ 0.01	13 %
Ad valorem taxes	**$ 3,180,755**	**$ 3,482,907**	**$ (302,152)**	**(9)%**
Average Ad valorem taxes per Boe	$ 0.89	$ 0.99	$ (0.10)	(10) %
Oil and natural gas production taxes	**$ 7,417,062**	**$ 8,055,567**	**$ (638,505)**	**(8)%**
Average Production taxes per Boe	$ 2.06	$ 2.28	$ (0.22)	(10) %
Production taxes as a percentage of total sales	4.59 %	4.16 %	0.43 %	10 %

Lease operating expenses. Our total LOE increased from $37.7 million to $39.9 million and LOE per Boe increased from $10.66 to $11.11. Total LOE increased in accordance with a 2% increase in production of 60,482 Boe, as a result of the additional production and well count from the Lime Rock Acquisition. The primary cost driver for the period was an increase in electricity costs of $2.9 million. Other cost increases included environmental sustainability of $0.4 million, and contract and lease services of $0.3 million. This was offset by reductions in LOE costs from workovers of $0.9 million, supplies, tools, and materials of $0.3 million, and hot oil costs of $0.2 million.

Gathering, transportation and processing costs. Our total GTP increased $63,738 from $273,683 to $337,421 and increased on a per Boe basis from $0.08 to $0.09. The increase in GTP costs was due to the higher natural gas Mcf and NGL barrels processed as well as a prior period adjustment for fee exempt owners.

Ad valorem taxes. Our total ad valorem taxes decreased from $3.5 million to $3.2 million and decreased on a per Boe basis from $0.99 to $0.89. Of the approximate $0.3 million decrease in ad valorem taxes, $0.5 million was from the reversal of the 2024 methane tax accrual for the waste emissions charge ("WEC"), which was repealed by Congress on March 14, 2025.

Oil and natural gas production taxes. Oil and natural gas production taxes as a percentage of oil and natural gas sales were 4.16% for the six months ended June 30, 2024 and increased to 4.59% for the six months ended June 30, 2025. Overall, the percentage was consistent period over period.

Other Costs and Operating Expenses for the Three Months Ended June 30, 2025 and 2024

	For the Three Months Ended			
	June 30, 2025	**June 30, 2024**	**Change**	**% Change**
Depreciation, depletion and amortization (DD&A):				
Depletion	$ 25,224,638	$ 24,325,186	$ 899,452	4 %
Depreciation	106,658	102,772	3,886	4 %
Amortization of financing lease assets	238,618	271,463	(32,845)	(12) %
Total depreciation, depletion and amortization	**$ 25,569,914**	**$ 24,699,421**	**$ 870,493**	**4 %**
Depletion per Boe	$ 13.02	$ 13.51	$ (0.49)	(4) %
Depreciation, depletion and amortization per Boe	$ 13.19	$ 13.72	$ (0.53)	(4) %
Asset retirement obligation ("ARO") accretion	**$ 382,251**	**$ 352,184**	**$ 30,067**	**9 %**
Operating lease expense	**$ 175,090**	**$ 175,090**	**$ —**	**— %**
General and administrative expense ("G&A"):				
General and administrative expense (excluding Share-based compensation)	$ 5,786,680	$ 5,635,756	$ 150,924	3 %
Share-based compensation	1,351,839	2,077,778	(725,939)	(35) %
Total general and administrative expense	**$ 7,138,519**	**$ 7,713,534**	**$ (575,015)**	**(7)%**
G&A per Boe	$ 3.68	$ 4.28	$ (0.60)	(14) %
G&A excluding Share-based compensation, per Boe	$ 2.99	$ 3.13	$ (0.14)	(4) %

Depreciation, depletion and amortization. Our depreciation, depletion and amortization increased from $24.7 million to $25.6 million, with $0.9 million of the increase from higher depletion. The increase in depletion was the result of a volume variance of $1.9 million due to an increase of 137,280 in Boe produced, offset by a price variance of $(1.0) million. driven by a lower depletion rate per Boe from higher reserves. Our average depreciation, depletion and amortization per Boe decreased from $13.72 per Boe to $13.19 per Boe.

Asset retirement obligation accretion. Our asset retirement obligation (“ARO”) accretion increased slightly from $352,184 to $382,251 due to additional ARO accretion associated with properties acquired in the Lime Rock Acquisition as well as new drilled and completed wells, offset by wells plugged and abandoned and sold.

Operating lease expense. Our operating lease expense costs were the same period over period.

General and administrative expense. General and administrative ("G&A") expense decreased from $7.7 million to $7.1 million. The $0.6 million cost decrease was primarily due to a decrease of $0.7 million in share-based compensation costs. Other cost reductions included a decrease of $0.3 million in legal fees, $0.2 million in additional costs capitalized for geological and geophysical ("G&G"), $0.1 million in reduced costs for environmental sustainablity, and a $0.1 million reduction in insurance costs. These cost reductions were offset by an increase of $0.8 million in salaries and bonuses.

Other Costs and Operating Expenses for the Six Months Ended June 30, 2025 and 2024

	For the Six Months Ended			
	June 30, 2025	June 30, 2024	Change	% Change
Depreciation, depletion and amortization (DD&A):				
Depletion	$ 47,479,214	$ 47,754,798	$ (275,584)	(1) %
Depreciation	203,278	204,709	(1,431)	(1) %
Amortization of financing lease assets	503,405	532,364	(28,959)	(5) %
Total depreciation, depletion and amortization	**$ 48,185,897**	**$ 48,491,871**	**$ (305,974)**	**(1)%**
Depletion per Boe	$ 13.21	$ 13.52	$ (0.31)	(2) %
Depreciation, depletion and amortization per Boe	$ 13.41	$ 13.73	$ (0.32)	(2) %
Asset retirement obligation ("ARO") accretion	**$ 708,800**	**$ 703,018**	**$ 5,782**	**1 %**
Operating lease expense	**$ 350,181**	**$ 350,181**	**$ —**	**— %**
General and administrative expense ("G&A"):				
General and administrative expense (excluding Share-based compensation)	$ 12,715,698	$ 11,381,146	$ 1,334,552	12 %
Share-based compensation	3,042,797	3,801,610	(758,813)	(20) %
Total general and administrative expense	**$ 15,758,495**	**$ 15,182,756**	**$ 575,739**	**4 %**
G&A per Boe	$ 4.39	$ 4.30	$ 0.09	2 %
G&A excluding Share-based compensation, per Boe	$ 3.54	$ 3.22	$ 0.32	10 %

Depreciation, depletion and amortization. Our depreciation, depletion and amortization decreased approximately $0.3 million from $48.5 million to $48.2 million, with substantially all of the reduction from lower depletion. The decrease in depletion was primarily due to a a price variance of $(1.1) million, from a lower depletion expense per Boe, due to an increase in the amortization base (Boe). Further, depletion had a volume variance of $0.8 million from a increase of 60,482 in Boe produced. Our average depreciation, depletion and amortization per Boe decreased from $13.73 per Boe to $13.41 per Boe.

Asset retirement obligation accretion. Our ARO accretion increased by $5,782 from $703,018 to $708,800 primarily as a result of newly acquired and drilled wells, offset by those plugged and abandoned and sold.

Operating lease expense. Our operating lease expense costs were the same period over period.

General and administrative expense. G&A expense increased approximately $0.6 million from $15.2 million to $15.8 million, with the $0.6 million cost increase primarily due to an increase of $2.3 million in salaries and bonuses (including impacts from severance paid), offset by reductions of $0.8 million in stock based compensation, $0.4 million in legal fees, $0.2 million in environmental sustainability, $0.2 million in credit loss expense, $0.1 million in additional costs capitalized for G&G, and a reduction of $0.1 million in other professional fees.

Other Income (Expense) for the Three Months Ended June 30, 2025 and 2024

	For the Three Months Ended			
	June 30, 2025	June 30, 2024	Change	% Change
Interest income	**$ 69,658**	**$ 144,933**	**$ (75,275)**	**(52)%**
Interest expense:				
Interest on revolving line of credit	$ 9,482,817	$ 9,521,775	$ (38,958)	— %
Fees associated with revolving line of credit	210,459	245,297	(34,838)	(14) %
Amortization of deferred financing costs	1,836,174	1,221,608	614,566	50 %
Interest on financing lease liabilities	27,638	31,422	(3,784)	(12) %
Interest paid for notes payable	10,645	9,986	659	7 %
Deferred cash payment accretion	189,671	—	189,671	100 %
Other interest	—	(83,961)	83,961	100 %
Total interest expense	**$ 11,757,404**	**$ 10,946,127**	**$ 811,277**	**7 %**
Gain (loss) on derivative contracts:				
Realized gain (loss):				
Crude oil	$ 433,301	$ (4,073,127)	$ 4,506,428	111 %
Natural gas	244,542	1,478,630	(1,234,088)	(83) %
Total realized gain (loss)	**$ 677,843**	**$ (2,594,497)**	**$ 3,272,340**	**126 %**
Unrealized gain (loss):				
Crude oil	$ 12,145,940	$ 2,308,594	$ 9,837,346	426 %
Natural gas	1,824,271	(1,542,696)	3,366,967	218 %
Total unrealized gain (loss)	**$ 13,970,211**	**$ 765,898**	**$ 13,204,313**	**1724 %**
Total gain (loss) on derivative contracts:	**$ 14,648,054**	**$ (1,828,599)**	**$ 16,476,653**	**901 %**
Gain (loss) on disposal of assets	**$ 155,293**	**$ 51,338**	**$ 103,955**	**202 %**
Other income	**$ 150,770**	**$ —**	**$ 150,770**	**100 %**

Interest income. Interest income decreased from $144,933 to $69,658 due to lower interest earned from depositing excess cash balances in bank sweep accounts.

Interest expense. Interest expense increased from $10.9 million to $11.8 million primarily due to additional deferred financing costs recognized from the credit agreement modification which was completed in June 2025. Also impacting the increase in interest expense was the deferred cash payment accretion related to the Lime Rock acquisition which closed at the end of March 2025. Although the Company had higher amounts outstanding on its Credit Facility, with a weighted average daily debt of approximately $456.3 million during the second quarter of 2025 compared to approximately $420.3 million during the second quarter of 2024, the interest on the revolving line of credit decreased slightly due to a meaningful reduction in interest rates, with a weighted average annual interest rate of 8.5% in the second quarter of 2025 compared to 9.3% in the second quarter of 2024.

Gain (loss) on derivative contracts. We recorded a gain on derivative contracts of $14.6 million for the three months ended June 30, 2025 compared to a loss on derivative contracts of $1.8 million for the three months ended June 30, 2024. For the derivative contract settlements, we recorded a realized gain of $0.7 million for the three months ended June 30, 2025 and a realized loss of $2.6 million for the three months ended June 30, 2024. The change of $3.3 million in the realized gain (loss) was a result of more favorable settlements of crude oil derivative contracts during the current year. For the marked-to-market contracts, we recorded an unrealized gain of $14.0 million for the three months ended June 30, 2025 and an unrealized gain of $0.8 million for the three months ended June 30, 2024. The change in position was primarily due to the changes in crude oil futures prices.

Gain (loss) on disposal of assets. The Company's gain on disposal of assets increased by $103,955 from $51,338 during the three months ended June 30, 2024 to $155,293 during the three months ended June 30, 2025, with $89,716 of the increase from the sale of leased vehicles, and the remainder of $14,239 due to selling owned vehicles in the prior period.

Other income. During the three months ended June 30, 2025, the Company recorded $150,770 of other income from a pipeline easement lease.

Other Income (Expense) for the Six Months Ended June 30, 2025 and 2024

	For the Six Months Ended			
	June 30, 2025	**June 30, 2024**	**Change**	**% Change**
Interest income	**$ 159,716**	**$ 223,477**	**$ (63,761)**	**(29)%**
Interest expense:				
Interest on revolving line of credit	$ 17,430,459	$ 19,287,826	$ (1,857,367)	(10) %
Fees associated with revolving line of credit	487,848	484,925	2,923	1 %
Amortization of deferred financing costs	3,074,667	2,443,215	631,452	26 %
Interest on financing lease liabilities	56,379	62,739	(6,360)	(10) %
Interest paid for notes payable	17,166	16,366	800	5 %
Deferred cash payment accretion	189,671	—	189,671	100 %
Other interest	—	150,000	(150,000)	(100) %
Total interest expense	**$ 21,256,190**	**$ 22,445,071**	**$ (1,188,881)**	**(5)%**
Gain (loss) on derivative contracts:				
Realized gain (loss):				
Crude oil	$ (206,966)	$ (6,812,097)	$ 6,605,131	97 %
Natural gas	331,215	2,756,085	(2,424,870)	(88) %
Total realized gain (loss)	**$ 124,249**	**$ (4,056,012)**	**$ 4,180,261**	**103 %**
Unrealized gain (loss):				
Crude oil	$ 14,487,365	$ (14,685,728)	$ 29,173,093	199 %
Natural gas	(892,350)	(2,101,354)	1,209,004	58 %
Total unrealized gain (loss)	**$ 13,595,015**	**$ (16,787,082)**	**$ 30,382,097**	**181 %**
Total gain (loss) on derivative contracts:	**$ 13,719,264**	**$ (20,843,094)**	**$ 34,562,358**	**166 %**
Gain (loss) on disposal of assets	**$ 279,903**	**$ 89,693**	**$ 190,210**	**212 %**
Other income	**$ 159,712**	**$ 25,686**	**$ 134,026**	**522 %**

Interest income. Interest income decreased $63,761 from $223,477 to $159,716, from a reduction of $71,128 from depositing excess cash balances in bank sweep accounts, offset by an increase of $7,367 in severance tax interest payments**.**

Interest expense. Interest expense decreased by approximately $1.2 million from $22.4 million to $21.3 million as a result of lower interest rates, with a weighted average annual interest rate of 8.4% during the six months ended June 30, 2025 compared to 9.3% during the six months ended June 30, 2024. Slightly offsetting this impact was higher amounts outstanding on our Credit Facility, with a weighted average daily debt of approximately $425.0 million during the six months ended June 30, 2025 compared to approximately $424.6 million during the six months ended June 30, 2024. Further offsetting was the increase in deferred financing costs recognized from the credit agreement modification.

Gain (loss) on derivative contracts. We recorded a gain on derivative contracts of $13.7 million for the six months ended June 30, 2025 and a loss on derivative contracts of $20.8 million for the six months ended June 30, 2024. For the derivative contract settlements, we recorded a realized gain of $0.1 million for the six months ended June 30, 2025 and a realized loss of $4.1 million for the six months ended June 30, 2024. The change of $4.2 million in the realized derivative gain (loss) was a result of more favorable settlements of crude oil derivative contracts during the current year. For the marked-to-market contracts, we recorded an unrealized gain of $13.6 million for the six months ended June 30, 2025 and an unrealized loss of $16.8 million for the six months ended June 30, 2024. This positive change in unrealized derivatives primarily was due to the changes in crude oil futures prices on derivative contracts in the Company's portfolio.

Gain (loss) on disposal of assets. The Company's gain on disposal of assets increased by $190,210 from $89,693 to $279,903 with $182,945 of the increase from the sale of leased vehicles as well as $7,265 from more favorable sales of Company owned vehicles.

Other income. Other income increased $134,026 from $25,686 to $159,712 from due to an increase in income of $150,770 from a pipeline easement lease, offset by a reduction of $16,744 in income from the Company's charge card rebate program.

Provision for Income Taxes: for the Three Months Ended June 30, 2025 and 2024

	For the Three Months Ended			
	June 30, 2025	**June 30, 2024**	**Change**	**% Change**
Provision for Income Taxes:				
Deferred federal income tax provision	$ (5,776,325)	$ (6,427,828)	$ 651,503	10 %
Current state income tax provision	(147,461)	(152,385)	4,924	3 %
Deferred state income tax provision	(183,639)	(240,272)	56,633	24 %
Provision for Income Taxes	**$ (6,107,425)**	**$ (6,820,485)**	**$ 713,060**	**10 %**

Provision for income taxes. The provision for income taxes changed from a provision of $6.8 million for the three months ended June 30, 2024 to a provision of $6.1 million for the three months ended June 30, 2025. 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 2025, taking into account all applicable tax rates and laws.

Provision for Income Taxes: for the Six Months Ended June 30, 2025 and 2024

	For the Six Months Ended			
	June 30, 2025	**June 30, 2024**	**Change**	**% Change**
Provision for Income Taxes:				
Deferred federal income tax provision	$ (8,592,403)	$ (7,979,587)	$ (612,816)	(8) %
Current state income tax provision	(283,854)	(255,018)	(28,836)	(11) %
Deferred state income tax provision	(272,345)	(314,766)	42,421	13 %
Provision for Income Taxes	**$ (9,148,602)**	**$ (8,549,371)**	**$ (599,231)**	**(7)%**

Provision for income taxes. The provision for income taxes changed from a provision of $8.5 million for the six months ended June 30, 2024 to a provision of $9.1 million for the six months ended June 30, 2025. 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 2025, taking into account all applicable tax rates and laws.

Liquidity and Capital Resources

As of June 30, 2025, we had cash on hand of $0.0 million, compared to $1.9 million as of December 31, 2024. We strive to keep our cash balance as low as possible to minimize our outstanding debt and associated interest. At certain times we reflect a zero book balance while utilizing the float on outstanding checks. We had net cash provided by operating activities for the six months ended June 30, 2025 of $61.7 million, compared to net cash provided by operating activities of $95.8 million for the same period in 2024, which was primarily due to lower year to date revenues, which resulted in less cash received from purchasers. We had net cash used in investing activities of $121.0 million for the six months ended June 30, 2025, compared to net cash used in investing activities of $76.4 million for the same period in 2024, driven by the payments made for the Lime Rock Acquisition in the first half of 2025, with no comparable payments made in the first half of 2024. This increase in acquisition payments was offset by a reduction in payments to develop oil and natural gas properties. Net cash provided by financing activities was $57.4 million for the six months ended June 30, 2025 and net cash used in financing activities was $18.6 million for the six months ended June 30, 2024, during which time $63 million was the net borrowing and $18.0 million was the net paydown of principal on our Credit Facility, respectively.

We will continue to focus on maximizing cash flow in 2025 through a combination of cost monitoring and prudent capital allocation, which includes prioritizing our capital to projects we believe will provide high rates of return in the current commodity price environment. We will continue our pursuit of acquisitions and business combinations, seeking opportunities that we believe will provide high margin properties with attractive returns at current commodity prices, ultimately pushing to reduce our debt level and maximize our liquidity.

Availability of Capital Resources under Credit Facility

As of June 30, 2025, $448 million was outstanding on our Credit Facility and we were in compliance with all of the covenants under the Credit Facility. The Credit Facility matures in June 2029. The borrowing base under our Credit Facility is $585 million. The borrowing base is redetermined semi-annually each May and November. See "NOTE 8 — REVOLVING LINE OF CREDIT" in the Notes to the condensed financial statements for more information on our Credit Facility.

Derivative Financial Instruments

The following table reflects the contracts outstanding as of June 30, 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)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
Swaps:								
Hedged volume (Bbl)	471,917	241,755	608,350	577,101	171,400	529,000	509,500	492,000
Weighted average swap price	$ 68.64	$ 65.56	$ 67.95	$ 67.41	$ 62.26	$ 65.34	$ 62.82	$ 60.45
Two-way collars:								
Hedged volume (Bbl)	225,400	404,800	—	—	379,685	—	—	—
Weighted average put price	$ 65.00	$ 60.00	$ —	$ —	$ 60.00	$ —	$ —	$ —
Weighted average call price	$ 78.91	$ 75.68	$ —	$ —	$ 72.50	$ —	$ —	$ —

	Gas Hedges (Henry Hub)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
NYMEX Swaps:								
Hedged volume (MMBtu)	300,500	128,400	140,600	662,300	121,400	613,300	—	—
Weighted average swap price	$ 3.88	$ 4.25	$ 4.20	$ 3.54	$ 4.22	$ 3.83	$ —	$ —
Two-way collars:								
Hedged volume (MMBtu)	309,350	748,000	694,500	139,000	648,728	128,000	717,000	694,000
Weighted average put price	$ 3.17	$ 3.10	$ 3.50	$ 3.50	$ 3.10	$ 3.50	$ 3.99	$ 3.00
Weighted average call price	$ 4.98	$ 4.40	$ 5.11	$ 5.42	$ 4.24	$ 5.42	$ 5.21	$ 4.32

	Oil Hedges (basis differential)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
Argus basis swaps:								
Hedged volume (Bbl)	183,000	276,000	—	—	—	—	—	—
Weighted average spread price (1)	$ 1.00	$ 1.00	$ —	$ —	$ —	$ —	$ —	$ —

	Gas Hedges (basis differential)							
	Q3 2025	Q4 2025	Q1 2026	Q2 2026	Q3 2026	Q4 2026	Q1 2027	Q2 2027
El Paso Permian Basin basis swaps:								
Hedged volume (MMBtu)	381,725	363,200	—	—	—	—	700,000	—
Weighted average spread price (2)	$ 1.69	$ 1.69	$ —	$ —	$ —	$ —	$ 0.74	$ —

(1) The oil basis swap hedges are calculated as the fixed price (weighted average spread price above) less the difference between WTI Midland and WTI Cushing, in the issue of Argus Americas Crude.

(2) 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.

Derivative financial instruments are recorded at fair value and included as either assets or liabilities in the accompanying Condensed Balance Sheets. 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 accompanying Condensed Statements of Operations.

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. At June 30, 2025, 86% of our derivative instruments were with lenders under our Credit Facility.

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 June 30, 2025, we had no off-balance sheet financing arrangements.

Capital Resources for Future Acquisition and Development Opportunities

We continuously evaluate potential acquisitions and development opportunities. To the extent possible, we intend to acquire producing properties with lower-risk undeveloped drilling opportunities rather than properties with higher-risk exploratory opportunities. We do not intend to limit our evaluation to any one state, but we presently have no intention to acquire offshore properties or properties located outside of the United States.

The pursuit of and the acquisition of accretive oil and gas properties is highly competitive and may require substantially greater capital than we currently have available and obtaining additional capital may require that we obtain either short-term or long-term debt or sell our equity or both. Further, it may be necessary for us to retain outside consultants and others in our endeavors to locate desirable oil and gas properties.

The process of acquiring one or more additional oil and gas properties would impact our financial position, reduce our cash position and likely increase our debt levels. The types of costs that we may incur include the costs to retain consultants and investment bankers specializing in the purchase of oil and gas properties, obtaining petroleum engineering reports relative to the oil and gas properties that we are investigating, legal fees associated with any such acquisitions including title reports, SEC reporting expenses, and negotiating definitive agreements. Additionally, accounting fees may be incurred relative to obtaining and evaluating historical and pro forma information regarding oil and gas properties. Even though we may incur these costs, there is no assurance that we will ultimately be able to consummate additional acquisitions of oil and gas producing properties.

Item 3: 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 decreases in oil and natural gas prices. Realized pricing is primarily driven by the prevailing domestic price for crude oil and spot prices in the Permian Basin. 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. A significant decrease 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.

Customer Credit Risk

Our principal exposure to credit risk is through receivables from the sale of our oil and natural gas production (approximately $36.3 million as of June 30, 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. Refer to the following table for detail on the top three purchasers of our oil, natural gas, and NGL revenues for the six months ended June 30, 2025. We believe that the loss of any of these purchasers would not materially impact our business as we could readily find other purchasers for our oil and natural gas.

	For the Six Months Ended	As of
	June 30, 2025	June 30, 2025
	Percentage of Oil, Natural Gas, and Natural Gas Liquids Revenues	Percentage of accounts receivables from the sale of our oil and natural gas production
Purchaser:		
Phillips 66 Company ("Phillips")	66%	73%
Concord Energy LLC ("Concord")	13%	10%
NGL Crude Partners ("NGL Crude")	9%	7%

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 June 30, 2025, we had $448 million outstanding on our Credit Facility with a weighted average annual interest rate for the six months ended June 30, 2025 of 8.4%. A 1% change in the interest rate on our Credit Facility would result in an estimated $4.5 million change in our annual interest expense. See "NOTE 8 — REVOLVING LINE OF CREDIT" in the Notes to the condensed 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" for a discussion of other risks and uncertainties we face in our business.

Item 4: Controls and Procedures

Evaluation of disclosure controls and procedures.

Our management, with the participation of Paul D. McKinney, our principal executive officer, and Travis T. Thomas, our principal financial officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Exchange Act. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints, and that management is required to apply its judgment in evaluating the benefits of possible controls and procedures relative to their costs.

Based on management's evaluation, Messrs. McKinney and Thomas concluded that our disclosure controls and procedures as of the end of the period covered by this report were effective in ensuring that information required to be disclosed by us in reports that we file or submit under the Exchange Act (i) is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and (ii) is accumulated and communicated to the Company's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

We will continue to monitor and evaluate the effectiveness of our disclosure controls and procedures and our internal controls over financial reporting on an ongoing basis and are committed to taking further action and implementing additional enhancements or improvements, as necessary and as funds allow.

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 three months ended June 30, 2025 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1: Legal Proceedings

There were no material developments during the quarter ended June 30, 2025 in the legal proceeding described in our Annual Report on Form 10-K for the year ended December 31, 2024.

Item 1A: Risk Factors

We are subject to certain risks and hazards due to the nature of the business activities we conduct. For a discussion of these risks, see "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2024 as filed with the SEC. We may experience additional risks and uncertainties not currently known to us. Further, as a result of developments occurring in the future, conditions that we currently deem to be immaterial may also materially and adversely affect us. Any such risks may materially and adversely affect our business, financial condition, cash flows, and results of operations.

Item 2: Unregistered Sales of Equity Securities and Use of Proceeds

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.

Item 3: Defaults Upon Senior Securities

None.

Item 4: Mine Safety Disclosures

None.

Item 5: Other Information

During the quarter ended June 30, 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 6: Exhibits

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	File No.	Exhibit	Filing Date	Filed Here-with	Furnished Herewith
31.1	Rule 13a-14(a) Certification by Chief Executive Officer					X	
31.2	Rule 13a-14(a) Certification by Chief Financial Officer					X	
32.1	Section 1350 Certification of Chief Executive Officer						X
32.2	Section 1350 Certification Chief Financial Officer						X
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)						

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	Ring Energy, Inc.
Date: August 6, 2025	By: /s/ Paul D. McKinney Paul D. McKinney Chief Executive Officer (Principal Executive Officer)
Date: August 6, 2025	By: /s/ Travis T. Thomas Travis T. Thomas Chief Financial Officer (Principal Financial and Accounting Officer)

Exhibit 31.1

CERTIFICATIONS

I, Paul D. McKinney, certify that:

1. I have reviewed this Form 10-Q for the quarter ended June 30, 2025 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: August 6, 2025

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

Exhibit 31.2

CERTIFICATIONS

I, Travis T. Thomas, certify that:

1. I have reviewed this Form 10-Q for the quarter ended June 30, 2025 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: August 6, 2025

/s/ Travis T. Thomas
Travis T. Thomas, CFO
(Principal Financial Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350

AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the quarterly report of Ring Energy, Inc. (the “Company”) on Form 10-Q for the quarter ended June 30, 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: August 6, 2025

/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 quarterly report of Ring Energy, Inc. (the “Company”) on Form 10-Q for the quarter ended June 30, 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: August 6, 2025

/s/ Travis T. Thomas
Travis T. Thomas
Chief Financial Officer
(Principal Financial Officer)

The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of the Report or as a separate disclosure document.

A signed original of this written statement required by Section 906 has been provided to, and will be retained by, the Company and furnished to the Securities and Exchange Commission or its staff upon request.