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

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2023
or

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

For the transition period from______ to ______
Commission file number: 1-13283

RANGER OIL CORPORATION
(Exact name of registrant as specified in its charter)

Virginia	23-1184320
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

16285 Park Ten Place, Suite 500
Houston, TX 77084
(Address of principal executive offices) (Zip Code)

(713) 722-6500
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class A Common Stock, $0.01 Par Value	**ROCC**	**The Nasdaq Stock Market LLC**

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

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

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

As of May 3, 2023, there were 41,557,708 shares of common stock outstanding, including 19,008,710 shares of Class A Common Stock and 22,548,998 shares of Class B Common Stock.

RANGER OIL CORPORATION
QUARTERLY REPORT ON FORM 10-Q

For the Quarterly Period Ended March 31, 2023

Table of Contents

Part I. FINANCIAL INFORMATION

Item 1. Financial Statements

RANGER OIL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS – UNAUDITED
(in thousands, except per share data)

	Three Months Ended March 31,	
	2023	**2022**
Revenues and other		
Crude oil	$ 236,932	$ 226,732
Natural gas liquids	12,154	16,740
Natural gas	8,345	12,127
Other operating income, net	717	856
Total revenues and other	258,148	256,455
Operating expenses		
Lease operating	29,990	18,102
Gathering, processing and transportation	10,180	9,040
Production and ad valorem taxes	16,042	13,140
General and administrative	12,668	9,779
Depreciation, depletion and amortization	85,303	50,893
Total operating expenses	154,183	100,954
Operating income	103,965	155,501
Other income (expense)		
Interest expense, net of amounts capitalized	(14,718)	(10,697)
Gain on extinguishment of debt	—	2,157
Derivative gains (losses)	25,658	(167,887)
Other, net	(123)	76
Income (loss) before income taxes	114,782	(20,850)
Income tax (expense) benefit	(991)	189
Net income (loss)	113,791	(20,661)
Net (income) loss attributable to Noncontrolling interest	(61,792)	10,676
Net income (loss) attributable to Class A common shareholders	$ 51,999	$ (9,985)
Net income (loss) per share attributable to Class A common shareholders:		
Basic	$ 2.74	$ (0.47)
Diluted	$ 2.67	$ (0.47)
Weighted average shares outstanding – basic	18,975	21,107
Weighted average shares outstanding – diluted	19,623	21,107

See accompanying notes to condensed consolidated financial statements.

RANGER OIL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) – UNAUDITED
(in thousands)

	Three Months Ended March 31,	
	2023	**2022**
Net income (loss)	$ 113,791	$ (20,661)
Other comprehensive income (loss):		
Change in pension and postretirement obligations, net of tax [1]	32	—
Comprehensive income (loss)	113,823	(20,661)
Net (income) loss attributable to Noncontrolling interest	(61,792)	10,676
Other comprehensive income attributable to Noncontrolling interest [1]	(17)	—
Comprehensive income (loss) attributable to Class A common shareholders	$ 52,014	$ (9,985)

[1] The amounts for 2022 are minimal and round down to zero .

See accompanying notes to condensed consolidated financial statements.

RANGER OIL CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS – UNAUDITED
(in thousands, except share data)

	March 31, 2023	December 31, 2022
Assets		
Current assets		
Cash and cash equivalents	$ 12,354	$ 7,592
Accounts receivable, net of allowance for credit losses	138,546	139,715
Derivative assets	23,756	29,714
Prepaid and other current assets	18,460	22,264
Assets held for sale	1,186	1,186
Total current assets	194,302	200,471
Property and equipment, net	1,874,836	1,809,000
Derivative assets	216	316
Other assets	17,278	4,420
Total assets	$ 2,086,632	$ 2,014,207
Liabilities and Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 239,792	$ 265,609
Derivative liabilities	32,286	67,933
Total current liabilities	272,078	333,542
Deferred income taxes	7,022	6,216
Derivative liabilities	1,320	3,416
Other non-current liabilities	13,131	9,934
Long-term debt, net	629,480	604,077
Commitments and contingencies (Note 11)		
Equity		
Preferred stock of $0.01 par value – 5,000,000 shares authorized; none issued as of March 31, 2023 and December 31, 2022	—	—
Class A common stock, $0.01 par value – 110,000,000 shares authorized; 18,982,425 and 19,074,864 issued and outstanding as of March 31, 2023 and December 31, 2022, respectively	190	190
Class B common stock, $0.01 par value – 30,000,000 shares authorized; 22,548,998 shares issued and outstanding as of March 31, 2023 and December 31, 2022	2	2
Paid-in capital	216,941	220,062
Retained earnings	314,801	264,256
Accumulated other comprehensive loss	(96)	(111)
Ranger Oil shareholders' equity	531,838	484,399
Noncontrolling interest	631,763	572,623
Total equity	1,163,601	1,057,022
Total liabilities and equity	$ 2,086,632	$ 2,014,207

See accompanying notes to condensed consolidated financial statements.

RANGER OIL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – UNAUDITED
(in thousands)

	Three Months Ended March 31,	
	2023	**2022**
Cash flows from operating activities		
Net income (loss)	$ 113,791	$ (20,661)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Gain on extinguishment of debt	—	(2,157)
Depreciation, depletion and amortization	85,303	50,893
Derivative contracts:		
Net (gains) losses	(25,658)	167,887
Cash settlements and premiums paid, net	(7,358)	(29,408)
Deferred income tax expense (benefit)	806	(721)
Non-cash interest expense	933	800
Share-based compensation	2,051	924
Other, net	349	(182)
Changes in operating assets and liabilities, net	(9,968)	(33,540)
Net cash provided by operating activities	160,249	133,835
Cash flows from investing activities		
Capital expenditures	(171,464)	(71,173)
Proceeds from sales of assets and other, net	447	656
Net cash used in investing activities	(171,017)	(70,517)
Cash flows from financing activities		
Proceeds from credit facility borrowings	156,000	50,000
Repayments of credit facility borrowings	(131,000)	(130,000)
Repayments of acquired and other debt	(238)	(83)
Payments for share repurchases	(4,816)	—
Distributions to Noncontrolling interest	(1,691)	—
Dividends paid	(1,438)	—
Withholding taxes for share-based compensation	(1,287)	(445)
Debt issuance costs paid	—	(113)
Net cash provided by (used in) financing activities	15,530	(80,641)
Net increase (decrease) in cash and cash equivalents	4,762	(17,323)
Cash and cash equivalents – beginning of period	7,592	23,681
Cash and cash equivalents – end of period	$ 12,354	$ 6,358
Supplemental disclosures:		
Cash paid for:		
Interest, net of amounts capitalized	$ 22,997	$ 20,214
Non-cash investing and financing activities:		
Changes in accrued liabilities related to capital expenditures	$ (22,408)	$ 9,361
ROU assets obtained in exchange for lease obligations:		
Operating leases	$ 15,865	$ —

See accompanying notes to condensed consolidated financial statements.

RANGER OIL CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF EQUITY - UNAUDITED
(in thousands)

	Shares										
	Preferred Shares Outstanding	Class A Common Shares	Class B Common Shares Outstanding	Preferred Stock	Class A Common Stock	Class B Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Equity
Balance as of December 31, 2022	—	19,075	22,549	$ —	$ 190	$ 2	$ 220,062	$ 264,256	$ (111)	$ 572,623	$ 1,057,022
Net income	—	—	—	—		—	—	51,999	—	61,792	113,791
Repurchase of Class A common stock	—	(122)	—	—	(1)	—	(4,863)	—	—	—	(4,864)
Change in ownership, net	—	—	—	—		—	978	—	—	(978)	—
Distributions to Noncontrolling interest	—	—	—	—		—	—	—	—	(1,691)	(1,691)
Dividends declared ($0.075 per share of Class A common stock)	—	—	—	—		—	—	(1,454)	—	—	(1,454)
Common stock issued related to share-based compensation and other, net [1]	—	29	—	—	1	—	764		15	17	797
Balance as of March 31, 2023	—	18,982	22,549	$ —	$ 190	$ 2	$ 216,941	$ 314,801	$ (96)	$ 631,763	$ 1,163,601

[1] Includes equity-classified share-based compensation of $2.1 million during the three months ended March 31, 2023. During the three months ended March 31, 2023, 29,418 of Class A common stock, par value $0.01 per share ("Class A Common Stock") were issued in connection with the vesting of certain time-vested restricted stock units ("RSUs") and performance-based restricted stock units ("PRSUs"), net of shares withheld for income taxes.

	Shares										
	Preferred Shares Outstanding	Class A Common Shares	Class B Common Shares Outstanding	Preferred Stock	Class A Common Stock	Class B Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Total Equity
Balance as of December 31, 2021	—	21,090	22,549	$ —	$ 729	$ 2	$ 273,329	$ 49,583	$ (111)	$ 345,976	$ 669,508
Net loss	—	—	—	—	—	—	—	(9,985)	—	(10,676)	(20,661)
Common stock issued related to share-based compensation and other, net [1]	—	56	—	—	—	—	478	—	—	—	478
Balance as of March 31, 2022	—	21,146	22,549	$ —	$ 729	$ 2	$ 273,807	$ 39,598	$ (111)	$ 335,300	$ 649,325

[1] Includes equity-classified share-based compensation of $0.9 million during the three months ended March 31, 2022. During the three months ended March 31, 2022, 55,971 of Class A Common Stock were issued in connection with the vesting of certain RSUs, net of shares withheld for income taxes. No shares of Class A Common Stock were issued in connection with the vesting of PRSUs during the three months ended March 31, 2022.

See accompanying notes to condensed consolidated financial statements.

Note 1 – Organization and Description of Business

Ranger Oil Corporation (together with its consolidated subsidiaries, unless the context otherwise requires, "Ranger Oil," the "Company," "we," "us" or "our") is an independent oil and gas company focused on the onshore development and production of oil, natural gas liquids ("NGLs") and natural gas. Our current operations consist of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale (the "Eagle Ford") in South Texas. We operate in and report our financial results and disclosures as one segment, which is the development and production of crude oil, NGLs and natural gas.

Juniper Capital Advisors, L.P. ("Juniper Capital"), through its affiliates, JSTX Holdings, LLC ("JSTX") and Rocky Creek Resources, LLC ("Rocky Creek" and together with JSTX and Juniper Capital, "Juniper"), beneficially owned as of March 31, 2023 an approximate 54% equity interest in the Company through its ownership of 22,548,998 shares of our Class B common stock, par value of $0.01 per share ("Class B Common Stock") and 22,548,998 common units (the "Common Units") in our Up-C partnership subsidiary, ROCC Energy Holdings, L.P. (the "Partnership"). See Note 2 for further information.

Note 2 – Basis of Presentation and Significant Accounting Policies

Basis of Presentation

Our unaudited condensed consolidated financial statements include the accounts of Ranger Oil and all of our subsidiaries as of the relevant dates. Intercompany balances and transactions have been eliminated. A substantial noncontrolling interest in our subsidiaries is provided for in our condensed consolidated statements of operations and comprehensive income (loss) and our condensed consolidated balance sheets for the periods presented. Our condensed consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America ("GAAP") and the rules and regulations of the Securities Exchange Commission (the "SEC"). Preparation of these statements involves the use of estimates and judgments where appropriate. In the opinion of management, all adjustments considered necessary for a fair presentation of our condensed consolidated financial statements have been included. Our condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes included in our Annual Report on Form 10-K for the year ended December 31, 2022 ("2022 Annual Report"). Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

Principles of Consolidation

Ranger Oil is organized as an Up-C structure whereby Juniper owns all of the shares of the Company's Class B Common Stock which are non-economic voting only shares of the Company. Juniper's economic interest in the Company is held through its ownership of limited partner interests, the Common Units, in the Partnership. Pursuant to the amended and restated limited partnership agreement of the Partnership (the "Partnership Agreement"), the Company's ownership of Common Units in the Partnership at all times equals the number of shares of the Company's Class A Common Stock then outstanding, and Juniper's ownership of Common Units in the Partnership at all times equals the number of shares of Class B Common Stock then outstanding. The Partnership was formed for the purpose of executing the Company's reorganization with Juniper into an Up-C structure. The Partnership, through its subsidiaries, owns, operates, and manages oil and gas properties in Texas and manages the Company's outstanding debt and derivative instruments. The Company's wholly-owned subsidiary, ROCC Energy Holdings GP LLC (the "GP"), is the general partner of the Partnership. Subsidiaries of the Partnership own and operate all our oil and gas assets. Ranger Oil and the Partnership are holding companies with no other operations, material cash flows, or material assets or liabilities other than the equity interests in their subsidiaries.

The Common Units are redeemable (concurrently with the cancellation of an equivalent number of shares of Class B Common Stock) by Juniper at any time on a one-for-one basis in exchange for shares of Class A Common Stock or, if the Partnership elects, cash based on the 5-day average volume-weighted closing price for the Class A Common Stock immediately prior to the redemption. In determining whether to make a cash election, the Company would consider the interests of the holders of the Class A Common Stock, the Company's financial condition, results of operations, earnings, projections, liquidity and capital requirements, management's assessment of the intrinsic value of the Class A Common Stock, the trading price of the Class A Common Stock, legal requirements, covenant compliance, restrictions in the Company's debt agreements and other factors it deems relevant.

The Partnership is considered a variable interest entity for which the Company is the primary beneficiary. The Company has benefits in the Partnership through the Common Units, and it has power over the activities most significant to the Partnership's economic performance through its 100% controlling interest in the GP (which, accordingly, is acting as an agent on behalf of the Company). This conclusion was based on a qualitative analysis that considered the Partnership's governance structure and the GP's control over operations of the Partnership. The GP manages the business and affairs of the Partnership, including key Partnership decision-making, and the limited partners do not possess any substantive participating or kick-out rights that would allow Juniper to block or participate in certain operational and financial decisions that most significantly impact the Partnership's economic performance or that would remove the GP. As such, because the Company has both power and benefits in the Partnership, the Company determined it is the primary beneficiary of the Partnership and consolidates the Partnership in the Company's condensed consolidated financial statements. The Company reflects a noncontrolling interest in the condensed consolidated financial statements based on the proportion of Common Units owned by Juniper relative to the total number of Common Units outstanding. The noncontrolling interest is presented as a component of equity in the accompanying condensed consolidated financial statements and represents the ownership interest held by Juniper in the Partnership (the "Noncontrolling interest").

Noncontrolling Interest

The noncontrolling interest percentage may be affected by the issuance of shares of Class A Common Stock, repurchases or cancellation of Class A Common Stock, the exchange of Class B Common Stock and the redemption of Common Units (and concurrent cancellation of Class B Common Stock), among other things. The percentage is based on the proportionate number of Common Units held by Juniper relative to the total Common Units outstanding. As of March 31, 2023, the Company owned 18,982,425 Common Units, representing a 45.7% limited partner interest in the Partnership, and Juniper owned 22,548,998 Common Units, representing the remaining 54.3% limited partner interest. As of December 31, 2022, the Company owned 19,074,864 Common Units, representing a 45.8% limited partner interest in the Partnership, and Juniper owned 22,548,998 Common Units, representing the remaining 54.2% limited partner interest. During the three months ended March 31, 2023, changes in the ownership interests were the result of share repurchases and issuances of Class A Common Stock in connection with the vesting of employees' share-based compensation. See Note 12 for information regarding share repurchases and Note 13 for vesting of share-based compensation.

When the Company's relative ownership interest in the Partnership changes, adjustments to Noncontrolling interest and Paid-in capital, tax effected, will occur. Because these changes in the ownership interest in the Partnership do not result in a change of control, the transactions are accounted for as equity transactions under Accounting Standards Codification Topic 810, *Consolidation*, which requires that any differences between the carrying value of the Company's basis in the Partnership and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest. Additionally, based on the Partnership Agreement, there are no substantive profit sharing arrangements that would cause distributions to be other than pro rata. Therefore, profits and losses are attributed to the Class A common shareholders and noncontrolling interest pro rata based on ownership interests in the Partnership.

Significant Accounting Policies

The Company's significant accounting policies are described in "Note 3 – Summary of Significant Accounting Policies" of the Notes to Consolidated Financial Statements in its 2022 Annual Report and are supplemented by the notes included in this Quarterly Report on Form 10-Q. The financial statements and related notes included in this report should be read in conjunction with the Company's 2022 Annual Report.

Recent Accounting Pronouncements

We consider the applicability and impact of all Accounting Standard Updates ("ASUs"). ASUs not listed below were assessed and determined to be not applicable.

Adoption of Recently Issued Accounting Pronouncements

Effective January 1, 2023, we adopted ASU 2021-08, *Business Combinations (Topic 805): ("ASU 2021-08"): Accounting for Contract Assets and Contract Liabilities from Contracts with Customers.* ASU 2021-08 amends Topic 805 to require the acquirer in a business combination to record contract assets and contract liabilities in accordance with *Revenue from Contracts with Customers (Topic 606)* at acquisition as if it had originated the contract, rather than at fair value. As required, ASU 2021-08 will be applied prospectively to business combinations occurring on or after December 15, 2022. We adopted this update on January 1, 2023 and it did not have a material impact on our financial statements.

Note 3 – Transactions

Pending Baytex Merger

On February 27, 2023, we entered into an Agreement and Plan of Merger (the "Merger Agreement") with Baytex Energy Corp. ("Baytex") pursuant to which, among other things, the Company will merge with and into a wholly-owned subsidiary of Baytex with the Company surviving the merger as a wholly-owned subsidiary of Baytex (the "Baytex Merger"). Subject to the terms and conditions of the Merger Agreement, each share of our Class A Common Stock issued and outstanding immediately prior to the effective time of the closing of the Baytex Merger (including shares of our Class A Common Stock to be issued in connection with the exchange of the Class B Common Stock and Common Units for Class A Common Stock), will be converted automatically into the right to receive: (i) 7.49 Baytex common shares and (ii) $13.31 in cash. The transaction was unanimously approved by the board of directors of each company and JSTX and Rocky Creek delivered a support agreement to vote their outstanding shares in favor of the Baytex Merger. The Baytex Merger is expected to close in late second quarter or early third quarter of 2023, subject to the satisfaction of customary closing conditions, including the requisite shareholder and regulatory approvals.

Note 4 – Revenue Recognition

Revenue from Contracts with Customers

Crude oil. We sell our crude oil production to our customers at either the wellhead or a contractually agreed-upon delivery point, including certain regional central delivery point ("CDP") terminals or pipeline inter-connections. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality, location differentials and, if applicable, deductions for intermediate transportation. Costs incurred by us for gathering and transporting the products to an agreed-upon delivery point are recognized as a component of gathering, processing and transportation expense ("GPT") in our condensed consolidated statements of operations.

NGLs. We have natural gas processing contracts in place with certain midstream processing vendors. We deliver "wet" natural gas to our midstream processing vendors at the inlet of their processing facilities through gathering lines, certain of which we own and others which are owned by gathering service providers. Subsequent to processing, NGLs are delivered or transported to a third-party customer. Depending upon the nature of the contractual arrangements with the midstream processing vendors regarding the marketing of the NGL products, we recognize revenue for NGL products on either a gross or net basis. For those contracts where we have determined that we are the principal, and the ultimate third party is our customer, we recognize revenue on a gross basis, with associated processing costs presented as GPT expenses. For those contracts where we have determined that we are the agent and the midstream processing vendor is our customer, we recognize NGL product revenues on a net basis with processing costs presented as a reduction of revenue.

Natural gas. Subsequent to the processing of "wet" natural gas and the separation of NGL products, the "dry" or residue gas is purchased by the processor or delivered to us at the tailgate of the midstream processing vendors' facilities and sold to a third-party customer. We recognize revenue when control transfers to the customer considering factors associated with custody, title, risk of loss and other contractual provisions as appropriate. Pricing is based on a market index with adjustments for product quality and location differentials, as applicable. Costs incurred by us for gathering and transportation from the wellhead through the processing facilities are recognized as a component of GPT in our condensed consolidated statements of operations.

We record revenue in the month that our oil and gas production is delivered to our customers. However, the collection of revenues from oil and gas production may take up to 60 days following the month of production. Therefore, we make accruals for revenues and accounts receivable based on estimates of our share of production sold. We record any differences, which historically have not been significant, between the actual amounts ultimately received and the original estimates in the period they become finalized.

We apply a practical expedient which provides for an exemption from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less. Under our commodity product sales contracts, we bill our customers and recognize revenue when our performance obligations have been satisfied. At that time, we have determined that payment is unconditional. Accordingly, our commodity sales contracts do not create contract assets or liabilities.

Accounts Receivable from Contracts with Customers

Our accounts receivable consists mainly of trade receivables from commodity sales and joint interest billings due from partners on properties we operate. Our allowance for credit losses is entirely attributable to receivables from joint interest partners. We generally have the right to withhold future revenue distributions to recover past due receivables from joint interest owners. Generally, our oil, natural gas, and NGL receivables are collected within 30 to 60 days. The following table summarizes our accounts receivable by type as of the dates presented:

	March 31, 2023	December 31, 2022
Customers	$ 111,726	$ 109,149
Joint interest partners	26,501	30,730
Derivative settlements from counterparties [1]	732	437
Other	132	114
Total	139,091	140,430
Less: Allowance for credit losses	(545)	(715)
Accounts receivable, net of allowance for credit losses	$ 138,546	$ 139,715

[1] See Note 5 for information regarding our derivative instruments.

Note 5 – Derivative Instruments

We utilize derivative instruments, typically swaps, put options and call options which are placed with financial institutions that we believe are acceptable credit risks, to mitigate our financial exposure to commodity price volatility associated with anticipated sales of our future production and volatility in interest rates attributable to our variable rate debt instruments. Our derivative instruments are not designated as hedges for accounting purposes. While the use of derivative instruments limits the risk of adverse commodity price and interest rate movements, such use may also limit the beneficial impact of future product revenues and interest expense from favorable commodity price and interest rate movements. From time to time, we may enter into incremental derivative contracts in order to increase the notional volume of production we are hedging, restructure existing derivative contracts or enter into other derivative contracts resulting in modification to the terms of existing contracts. In accordance with our internal policies, we do not utilize derivative instruments for speculative purposes.

For our commodity derivatives, we typically combine swaps, purchased put options, purchased call options, sold put options and sold call options in order to achieve various hedging objectives. Certain of these objectives result in combinations that operate as collars which include purchased put options and sold call options, three-way collars, which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap, among others.

Commodity Derivatives [1]

The following table sets forth our commodity derivative positions, presented on a net basis by period of maturity, as of March 31, 2023:

	2Q2023	3Q2023	4Q2023	1Q2024	2Q2024
NYMEX WTI Crude Swaps					
Average Volume Per Day (bbl)	2,400	2,807	2,657	462	462
Weighted Average Swap Price ($/bbl)	$ 54.26	$ 54.92	$ 54.93	$ 58.75	$ 58.75
NYMEX WTI Crude Collars					
Average Volume Per Day (bbl)	23,214	16,304	8,967		
Weighted Average Purchased Put Price ($/bbl)	$ 67.81	$ 72.50	$ 72.27		
Weighted Average Sold Call Price ($/bbl)	$ 78.89	$ 88.35	$ 87.57		
MEH WTI CMA Crude Differential Swaps					
Average Volume Per Day (bbl)	13,187				
Weighted Average Swap Price ($/bbl)	$ 2.03				
NYMEX HH Swaps					
Average Volume Per Day (MMBtu)	7,500				
Weighted Average Swap Price ($/MMBtu)	$ 3.690				
NYMEX HH Collars					
Average Volume Per Day (MMBtu)	11,538	11,413	11,413	11,538	11,538
Weighted Average Purchased Put Price ($/MMBtu)	$ 2.500	$ 2.500	$ 2.500	$ 2.500	$ 2.328
Weighted Average Sold Call Price ($/MMBtu)	$ 2.682	$ 2.682	$ 2.682	$ 3.650	$ 3.000
HSC Basis Swaps					
Average Volume Per Day (MMBtu)	19,038	11,413	11,413		
HSC Basis Average Fixed Price ($/MMBtu)	$ (0.153)	$ (0.153)	$ (0.153)		
HSC Index Swap					
Average Volume Per Day (MMBtu)	6,319				
HSC Index Average Fixed Price ($/MMBtu)	$ (0.045)				
OPIS Mt. Belvieu Ethane Swaps					
Average Volume per Day (gal)	98,901	34,239	34,239	34,615	
Weighted Average Fixed Price ($/gal)	$ 0.2288	$ 0.2275	$ 0.2275	$ 0.2275	

[1] NYMEX WTI refers to New York Mercantile Exchange West Texas Intermediate and MEH refers to Magellan East Houston that serve as benchmarks for crude oil. NYMEX HH refers to NYMEX Henry Hub that serves as the benchmark for natural gas. HSC refers to Houston Ship Channel that serves as another benchmark for natural gas. OPIS Mt. Belvieu refers to Oil Price Information Service Mt. Belvieu that serves as the benchmark for ethane which represents a commodity proxy for NGLs.

Interest Rate Derivatives

Through May 2022, we had a series of interest rate swap contracts (the "Interest Rate Swaps") establishing fixed interest rates on a portion of our variable interest rate indebtedness. The notional amount of the Interest Rate Swaps totaled $300 million, with us paying a weighted average fixed rate of1.36% on the notional amount, and the counterparties paying a variable rate equal to LIBOR. As of March 31, 2023, we did not have any interest rate derivatives.

Financial Statement Impact of Derivatives

The impact of our derivative activities on net income (loss) is included within Derivatives gains (losses) on our condensed consolidated statements of operations. Derivative contracts that have expired at the end of a period, but for which cash had not been received or paid as of the balance sheet date, have been recognized as components of Accounts receivable, net of allowance for credit losses (see Note 4) and Accounts payable and accrued liabilities (see Note 9) on the condensed consolidated balance sheets. Adjustments to reconcile net income (loss) to net cash provided by operating activities include derivative gains and losses and cash settlements that are reported under Net (gains) losses and Cash settlements and premiums paid, net, on our condensed consolidated statements of cash flows, respectively.

The following table summarizes the effects of our derivative activities for the periods presented:

	Three Months Ended March 31,	
	2023	2022
Interest rate swap gains recognized in the condensed consolidated statements of operations	$ —	$ 83
Commodity gains (losses) recognized in the condensed consolidated statements of operations	25,658	(167,970)
	$ 25,658	$ (167,887)
Interest rate cash settlements recognized in the condensed consolidated statements of cash flows	$ —	$ (938)
Commodity cash settlements and premiums paid recognized in the condensed consolidated statements of cash flows	(7,358)	(28,470)
	$ (7,358)	$ (29,408)

The following table summarizes the fair values of our derivative instruments, which we elect to present on a gross basis, as well as the locations of these instruments on our condensed consolidated balance sheets as of the dates presented:

		Fair Values			
		March 31, 2023		December 31, 2022	
Type	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Commodity contracts	Derivative assets/liabilities – current	$ 23,756	$ 32,286	$ 29,714	$ 67,933
Commodity contracts	Derivative assets/liabilities – non-current	216	1,320	316	3,416
		$ 23,972	$ 33,606	$ 30,030	$ 71,349

As of March 31, 2023, we reported net commodity derivative liabilities of $9.6 million. The contracts associated with these positions are with seven counterparties for commodity derivatives, all of which are investment grade financial institutions and are participants in our revolving credit facility (the "Credit Facility"). This concentration may impact our overall credit risk in that these counterparties may be similarly affected by changes in economic or other conditions. Non-performance risk is incorporated by utilizing discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position.

The agreements underlying our derivative instruments include provisions for the netting of settlements with the counterparties for contracts of similar type. We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

See Note 10 for information regarding the fair value of our derivative instruments.

Note 6 – Property and Equipment, Net

The following table summarizes our property and equipment as of the dates presented:

	March 31, 2023	December 31, 2022
Oil and gas properties (full cost accounting method):		
Proved	$ 3,163,277	$ 3,013,854
Unproved	43,158	41,882
Total oil and gas properties	3,206,435	3,055,736
Other property and equipment [1]	31,307	30,969
Total properties and equipment	3,237,742	3,086,705
Accumulated depreciation, depletion, amortization and impairments	(1,362,906)	(1,277,705)
Total property and equipment, net	$ 1,874,836	$ 1,809,000

[1] As of March 31, 2023 and December 31, 2022, we had $ 1.2 million classified as Assets held for sale excluded from above.

Unproved property costs of $43.2 million and $41.9 million have been excluded from amortization as of March 31, 2023 and December 31, 2022, respectively. We transferred $0.9 million and $0.7 million of unproved leasehold costs, including capitalized interest, associated with proved undeveloped reserves, and acreage unlikely to be drilled or expiring acreage, to the full cost pool during the three months ended March 31, 2023 and 2022, respectively. We capitalized internal costs of $ 1.6 million and $1.4 million and interest of $0.9 million and $1.1 million during the three months ended March 31, 2023 and 2022, respectively, in accordance with our accounting policies. Average depreciation, depletion and amortization per barrel of oil equivalent of proved oil and gas properties was $19.45 and $14.98 for the three months ended March 31, 2023 and 2022, respectively.

Ceiling Test

Throughout 2022 and into 2023, commodity prices remained volatile due to supply disruptions resulting from the Russia-Ukraine war and related sanctions that began in first quarter of 2022 as well as shifts in production levels by the Organization of the Petroleum Exporting Countries ("OPEC") and Russia (together with OPEC, "OPEC+"). Beginning with an announcement in April 2022 of production cuts which took effect in November 2022, OPEC+ changed its strategy from one which had seen gradually increasing production throughout most of 2022 to cutting production. Then in April 2023, OPEC+ announced a surprise oil output cut of approximately 1.16 million barrels of oil per day ("MMbbl/d") bringing the total volume cuts by OPEC+ to over 3.66 MMbbl/d until the end of 2023. During 2022 and through the first quarter of 2023, WTI crude oil and natural gas prices ranged from over $120 per barrel ("bbl") and over $9 per million British thermal units ("MMBtu"), respectively, to lows of approximately $67 per bbl and under $2 per MMBtu, respectively, due to factors discussed above.

At the end of each quarterly reporting period, the unamortized cost of our oil and gas properties, net of deferred income taxes, is limited to the sum of the estimated after-tax discounted future net revenues from proved properties adjusted for costs excluded from amortization (the "Ceiling Test"). The Ceiling Test utilizes an average of commodity prices based on the closing prices on the first day of each month for the previous 12 months. We did not record any impairments of our oil and gas properties during the three months ended March 31, 2023 or 2022.

Note 7 – Long-Term Debt

The following table summarizes our debt obligations as of the dates presented:

	March 31, 2023	December 31, 2022
Credit Facility	$ 240,000	$ 215,000
9.25% Senior Notes due 2026	400,000	400,000
Other	—	238
Total	640,000	615,238
Less: Unamortized discount [1]	(2,878)	(3,055)
Less: Unamortized deferred issuance costs [1, 2]	(7,642)	(8,106)
Long-term debt	$ 629,480	$ 604,077

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[1] The discount and issuance costs of the 9.25% Senior Notes due 2026 are being amortized over its respective term using the effective-interest method.

[2] Excludes issuance costs associated with the Credit Facility, which represents costs attributable to the access to credit over its contractual term, that have been presented as a component of Other assets (see Note 9) and are being amortized over the term of the Credit Facility using the straight-line method.

Credit Facility

As of March 31, 2023, the Credit Facility had a $1.0 billion revolving commitment and a $950 million borrowing base with aggregate elected commitments of $500 million, and a $25 million sublimit for the issuance of letters of credit. Availability under the Credit Facility may not exceed the lesser of the aggregate elected commitments or the borrowing base less outstanding advances and letters of credit. The borrowing base under the Credit Facility is redetermined semi-annually, generally in the Spring and Fall of each year. Additionally, we and the Credit Facility lenders may, upon request, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us for general corporate purposes, including working capital.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 1.50% to 2.50%, determined based on the utilization level under the Credit Facility or (b) a term Secured Overnight Financing Rate (“SOFR”) reference rate, plus an applicable margin ranging from 2.50% to 3.50%, determined based on the utilization level under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on Eurodollar borrowings is payable every one, three or six months, at the election of the borrower, and is computed on the basis of a year of 360 days. At March 31, 2023, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 7.67%. Unused commitment fees are charged at a rate of 0.50%.

The Credit Facility requires us to maintain (1) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset), measured as of the last day of each fiscal quarter of 1.00 to 1.00 and (2) a maximum leverage ratio (consolidated indebtedness to adjusted earnings before interest, taxes, depreciation, depletion, amortization and exploration expenses, both as defined in the Credit Facility), measured as of the last day of each fiscal quarter of 3.50 to 1.00.

The Credit Facility also contains other customary affirmative and negative covenants as well as events of default and remedies. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility. As of March 31, 2023, we were in compliance with all debt covenants under the Credit Facility.

We had $240.0 million in outstanding borrowings and $1.0 million in outstanding letters of credit under the Credit Facility as of March 31, 2023. Factoring in the outstanding letters of credit, we had $259.0 million of availability under the Credit Facility as of March 31, 2023. During the three months ended March 31, 2022, we incurred and capitalized approximately $0.4 million of issue costs associated with amendments to the Credit Facility. We did not incur any issue costs associated with the Credit Facility during the three months ended March 31, 2023.

9.25% Senior Notes due 2026

On August 10, 2021, our indirect, wholly-owned subsidiary completed an offering of $400 million aggregate principal amount of senior unsecured notes due 2026 (the "9.25% Senior Notes due 2026") that bear interest at 9.25% and were sold at 99.018% of par. Obligations under the 9.25% Senior Notes due 2026 were assumed by ROCC Holdings, LLC (formerly, Penn Virginia Holdings, LLC, hereinafter referred to as "Holdings"), as borrower, and are guaranteed by the subsidiaries of Holdings that guarantee the Credit Facility.

Interest on the 9.25% Senior Notes due 2026 is payable semi-annually in arrears on February 15 and August 15 of each year. We may redeem the 9.25% Senior Notes due 2026 at any time in whole or in part from time to time at specified redemption prices.

The indenture governing the 9.25% Senior Notes due 2026 (the "Indenture") also contains other customary affirmative and negative covenants as well as events of default and remedies.

As of March 31, 2023, we were in compliance with all debt covenants under the Indenture.

Other Debt

During the three months ended March 31, 2023, we settled $0.2 million of other debt. During the three months ended March 31, 2022, $2.2 million of other debt was extinguished and recorded as a gain on extinguishment of debt.

Note 8 – Income Taxes

The income tax provision resulted in an expense of $1.0 million for the three months ended March 31, 2023. The federal portion was fully offset by an adjustment to the valuation allowance against our net deferred tax assets resulting in an effective tax rate of 0.9%, which is fully attributable to the State of Texas. Our net deferred income tax liability balance of $7.0 million as of March 31, 2023 is also fully attributable to the State of Texas and primarily related to property.

The income tax provision resulted in a benefit of $0.2 million for the three months ended March 31, 2022. The federal portion was fully offset by an adjustment to the valuation allowance against our net deferred tax assets resulting in an effective tax rate of 0.9%, which was fully attributable to the State of Texas.

We had no liability for unrecognized tax benefits as of March 31, 2023 and December 31, 2022. There were no interest and penalty charges recognized during the three months ended March 31, 2023 and 2022. Tax years from 2018 forward remain open to examination by the major taxing jurisdictions to which the Company is subject; however, net operating losses originating in prior years are subject to examination when utilized.

Note 9 – Supplemental Balance Sheet Detail

The following table summarizes components of selected balance sheet accounts as of the dates presented:

	March 31, 2023	December 31, 2022
Prepaid and other current assets:		
Inventories [1]	$ 16,305	$ 19,341
Prepaid expenses [2]	2,155	2,923
	$ 18,460	$ 22,264
Other assets:		
Deferred issuance costs of the Credit Facility, net of amortization	$ 2,926	$ 3,218
Right-of-use assets – operating leases [3]	14,197	989
Other	155	213
	$ 17,278	$ 4,420
Accounts payable and accrued liabilities:		
Trade accounts payable	$ 50,366	$ 58,592
Drilling and other lease operating costs	50,318	62,842
Revenue and royalties payable	101,418	104,512
Production, ad valorem and other taxes	11,764	10,547
Derivative settlements to counterparties	3,074	4,109
Compensation and benefits	3,197	6,927
Interest	5,432	14,655
Current operating lease obligations [3]	11,043	907
Other	3,180	2,518
	$ 239,792	$ 265,609
Other non-current liabilities:		
Asset retirement obligations	$ 8,960	$ 8,849
Non-current operating lease obligations [3]	3,373	200
Postretirement benefit plan obligations	798	885
	$ 13,131	$ 9,934

[1] Includes tubular inventory and well materials of $ 15.7 million and $ 18.7 million as of March 31, 2023 and December 31, 2022, respectively, and crude oil volumes in storage of $ 0.6 million as of both March 31, 2023 and December 31, 2022.

[2] The balances as of March 31, 2023 and December 31, 2022 include $ 0.5 million in each period for the prepayment of drilling and completion materials and services.

[3] The balances as of March 31, 2023 primarily relate to an amended drilling rig lease contract.

Note 10 – Fair Value Measurements

We apply the authoritative accounting provisions included in GAAP for measuring the fair value of both our financial and nonfinancial assets and liabilities. Fair value is an exit price representing the expected amount we would receive upon the sale of an asset or that we would expect to pay to transfer a liability in an orderly transaction with market participants at the measurement date.

Our financial instruments, including cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to their short-term maturities. As of March 31, 2023 and December 31, 2022, the carrying values of the borrowings outstanding under our Credit Facility approximate fair value as the borrowings bear interest at variables rates tied to current market rates and the applicable margins represent market rates. The fair value of our fixed rate 9.25% Senior Notes due 2026 is estimated based on the published market prices for issuances of similar risk and tenor and is categorized as Level 2 within the fair value hierarchy. As of March 31, 2023, the carrying amount and estimated fair value of total debt (before amortization of issuance costs) was $640.0 million and $661.5 million, respectively. As of December 31, 2022, the carrying amount and estimated fair value of total debt (before amortization of issuance costs) was $615.2 million and $616.4 million, respectively.

Recurring Fair Value Measurements

The fair values of our derivative instruments are measured at fair value on a recurring basis on our condensed consolidated balance sheets.The following tables summarize the valuation of those assets and liabilities as of the dates presented:

	As of March 31, 2023			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets:				
Commodity derivative assets – current	$ —	$ 23,756	$ —	$ 23,756
Commodity derivative assets – non-current	—	216	—	216
Total financial assets	$ —	$ 23,972	$ —	$ 23,972
Financial liabilities:				
Commodity derivative liabilities – current	$ —	$ 32,286	$ —	$ 32,286
Commodity derivative liabilities – non-current	—	1,320	—	1,320
Total financial liabilities	$ —	$ 33,606	$ —	$ 33,606

	As of December 31, 2022			
	Level 1	**Level 2**	**Level 3**	**Total**
Financial assets:				
Commodity derivative assets – current	$ —	$ 29,714	$ —	$ 29,714
Commodity derivative assets – non-current	—	316	—	316
Total financial assets	$ —	$ 30,030	$ —	$ 30,030
Financial liabilities:				
Commodity derivative liabilities – current	$ —	$ 67,933	$ —	$ 67,933
Commodity derivative liabilities – non-current	—	3,416	—	3,416
Total financial liabilities	$ —	$ 71,349	$ —	$ 71,349

We used the following methods and assumptions to estimate fair values for the financial assets and liabilities described below:

- *Commodity derivatives*: We determine the fair values of our commodity derivative instruments using industry-standard models that consider various assumptions including current market and contractual prices for the underlying instruments, implied volatilities, time value and non-performance risk. For the current market prices, we use third-party quoted forward prices, as applicable, for NYMEX WTI and MEH crude oil, NYMEX HH natural gas, HSC natural gas and OPIS Mt. Belvieu Ethane natural gas liquids closing prices as of the end of the reporting periods. Each of these is a Level 2 input.
- *Interest rate swaps*: We determined the fair values of our interest rate swaps using an income approach valuation technique which discounts future cash flows back to a single present value. We estimated the fair value of the swaps based on published interest rate yield curves as of the date of the estimate. Each of these was a Level 2 input. All interest rate swaps matured in May 2022, and as of March 31, 2023, we had not entered into any new interest rate derivative instruments.

Non-performance risk is incorporated by utilizing discount rates adjusted for the credit risk of our counterparties if the derivative is in an asset position, and our own credit risk if the derivative is in a liability position. See Note 5 for additional details on our derivative instruments.

Non-Recurring Fair Value Measurements

The most significant non-recurring fair value measurements utilized in the preparation of our condensed consolidated financial statements are those attributable to the initial determination of asset retirement obligations ("AROs") associated with the ongoing development of new oil and gas properties. The determination of the fair value of AROs is based upon regional market and facility specific information. The amount of an ARO and the costs capitalized represent the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor after discounting the future cost back to the date that the abandonment obligation was incurred using a rate commensurate with the risk, which approximates our cost of funds. Because these significant fair value inputs are typically not observable, we have categorized the initial estimates as Level 3 inputs.

Note 11 – Commitments and Contingencies

Drilling and Completion Commitments

As of March 31, 2023, we had contracts fortwo drilling rigs with remaining terms of less thantwo years.

Gathering and Intermediate Transportation Commitments

We have long-term agreements that provide us with field gathering and intermediate pipeline transportation services for a majority of our crude oil and condensate production in Lavaca and Gonzales Counties, Texas. We also have volume capacity support for certain downstream intrastate pipeline transportation. The following table provides details on these contractual arrangements as of March 31, 2023:

Description of contractual arrangement	Expiration of Contractual Arrangement	Gross Minimum Volume Commitment (MVC) (bbl/d)	Expiration of MVC
Field gathering agreement	February 2041	8,000	February 2031
Intermediate pipeline transportation services	February 2026	8,000	February 2026
Volume capacity support	April 2026	8,000	April 2026

Each of these arrangements also contain an obligation to deliver the first20,000 gross barrels of oil per day produced from Gonzales, Lavaca and Fayette Counties, Texas. For certain of our crude oil volumes gathered under the field gathering agreement, our rate includes an adjustment based on NYMEX WTI prices. As crude oil prices increase, up to a cap of $90 per bbl, the gathering rate escalates pursuant to the field gathering agreement.

During the 12-month period ended March 31, 2023 and excluding the potential impact of the effects of price escalation from commodity price changes, if any, the minimum fee requirements attributable to the MVC under the gathering, transportation and marketing agreements are as follows: $10.5 million for the remainder of 2023, approximately $13.9 million per year for 2024 through 2025, $7.8 million for 2026, $3.8 million per year for 2027 through 2030 and $0.6 million for 2031.

During the three months ended March 31, 2023 and 2022, we delivered more than the required20,000 gross barrels of oil per day and recorded total expense of $10.0 million and $10.2 million, respectively, for contractual fees in connection with these arrangements.

Crude Oil Storage

As of March 31, 2023, we had access to up to approximately180,000 barrels of dedicated tank capacity for no additional charge at the service provider’s CDP facility, in Lavaca County, Texas through February 2041. In addition, we had access for an additional 70,000 barrels of tank capacity at the CDP on a month-to-month basis, which can be terminated by either party with 45 days’ notice to the counterparty. Costs associated with this monthly agreement are in the form of a monthly fixed rate short-term lease and are charged as incurred on a monthly basis to GPT in our condensed consolidated statements of operations.

Other Agreements

We have a long-term dedication of certain specific leases under a crude purchase and throughput terminal agreement through 2032. Under the agreement, we have rights to transfer dedicated oil for delivery to a Gulf coast terminal in Point Comfort, Texas or oil may be transferred at alternate locations to third parties with a terminal fee.

We have agreements that provide us with field gathering, compression and short-haul transportation services for our natural gas production and gas lift for our hydrocarbon production under various terms through 2039.

We also have agreements that provide us with services to process our wet gas production into NGL products and dry, or residue, gas. Several agreements covering the majority of our wet gas production extend beyond three years, including one agreement that extends into 2029.

Legal, Environmental Compliance and Other

We are involved, from time to time, in various legal proceedings arising in the ordinary course of business. While the ultimate results of these proceedings cannot be predicted with certainty, our management believes that these claims will not have a material effect on our financial position, results of operations or cash flows. As of March 31, 2023 and December 31, 2022, we had an estimated reserve of approximately $0.1 million for certain claims made against us regarding previously divested operations included in Accounts payable and accrued liabilities on our condensed consolidated balance sheets.

As of March 31, 2023 and December 31, 2022, we had AROs of approximately $9.0 million and $8.8 million, respectively, attributable to the plugging of abandoned wells.

Additionally, we have entered into certain contractual arrangements for other products and services and have commitments under information technology licensing and service agreements, among others.

Note 12 – Shareholders' Equity

Capital Stock

As of March 31, 2023, the Company had two classes of common stock: Class A Common Stock and Class B Common Stock. The holders of record of Class A Common Stock and Class B Common Stock vote together as a single class on all matters on which holders of Class A Common Stock and Class B Common Stock are entitled to vote; except that certain directors are elected by holders of a majority of the shares of Class B Common Stock voting as a separate class.

The holders of Class A Common Stock have no preemptive rights to purchase shares of Class A Common Stock. Shares of Class A Common Stock are not subject to any redemption or sinking fund provisions and are not convertible into any of the Company's other securities. In the event of the Company's voluntary or involuntary liquidation, dissolution or winding up, holders of Class A Common Stock will share equally in the assets remaining after it pays its creditors and preferred shareholders. Holders of Class A Common Stock are entitled to receive dividends when and if declared by the Board of Directors.

Shares of Class B Common Stock are non-economic interests in the Company, and no dividends can be declared or paid on the Class B Common Stock. The holders of Class B Common Stock have no preemptive rights to purchase shares of Class B Common Stock. Shares of Class B common stock are not subject to any redemption or sinking fund provisions. In the event of the Company's voluntary or involuntary liquidation, dissolution or winding up, after payment or provision for payment of its debts and other liabilities, the holders of Class B Common Stock will be entitled to receive, out of its assets or proceeds thereof available for distribution to our shareholders, before any distribution of such assets or proceeds is made to or set aside for the holders of Class A Common Stock and any other of the Company's stock ranking junior to the Class B Common Stock as to such distribution, payment in full in an amount equal to $0.01 per share of Class B Common Stock. With the exception of the aforementioned distribution, the holders of shares of Class B Common Stock will not be entitled to receive any of the Company's assets in the event of its voluntary or involuntary liquidation, dissolution or winding up.

The Company's Class B Common Stock is not convertible into any of the Company's other securities. However, if a holder exchanges one common unit of the Partnership for one share of the Company's Class A Common Stock, it must also surrender to the Company a share of its Class B Common Stock for each common unit exchanged.

As of March 31, 2023, the Company had (i) 110,000,000 authorized shares of Class A Common Stock and 18,982,425 shares of Class A Common Stock issued and outstanding, (ii) 30,000,000 authorized shares of Class B Common Stock and 22,548,998 shares of Class B Common Stock issued and outstanding, and (iii) 5,000,000 authorized shares of preferred stock, par value $0.01 per share, and no shares of preferred stock issued or outstanding.

Dividends

On March 3, 2023, the Company's Board of Directors declared a cash dividend of $0.075 per share of Class A Common Stock. The dividend was paid on March 30, 2023 to holders of record of Class A Common Stock as of the close of business on March 17, 2023. In connection with any dividend, Ranger's operating subsidiary will also make a corresponding distribution to its common unitholders. During the first quarter of 2023, the dividend to the holders of our Class A Common Stock and distribution to common unitholders totaled $3.1 million in the aggregate. The Company's Credit Facility and the Indenture have restrictive covenants that limit its ability to pay dividends. See Note 15 for details on dividends declared subsequent to March 31, 2023.

Share Repurchase Program

On April 13, 2022, our Board of Directors approved a share repurchase program that authorized the Company to repurchase up to $100 million of its outstanding Class A Common Stock. The share repurchase authorization was effective immediately and was valid through March 31, 2023. On July 7, 2022, the Board of Directors authorized an increase in the share repurchase program from $100 million to $140 million and extended the term of the program through June 30, 2023. We do not intend to repurchase additional shares pending closing of the Baytex Merger.

During the three months ended March 31, 2023, we repurchased 121,857 shares of our Class A Common Stock at a total cost of $4.8 million and an average purchase price of $39.52. The share repurchases were recorded to Class A common stock and Paid-in capital on our condensed consolidated balance sheets. As of March 31, 2023, the remaining authorized repurchase amount under the share repurchase program was $60.0 million.

On August 16, 2022, the Inflation Reduction Act was signed into law and imposes a 1% excise tax on the repurchase of stock by publicly traded U.S. corporations. The excise tax is effective for stock repurchases after December 31, 2022. Based on the total share repurchases during the three months ended March 31, 2023, we recognized less than $0.1 million of additional cost within Paid-in capital associated with the excise tax for these share repurchases.

Change in Ownership of Consolidated Subsidiaries

The following table summarizes changes in the ownership interest in consolidated subsidiaries during the periods presented:

	Three Months Ended March 31,	
	2023	**2022**
Net income (loss) attributable to Class A common shareholders	$ 51,999	$ (9,985)
Transfers from the noncontrolling interest, net [1]	978	N/A
Change from Net income (loss) attributable to Class A common shareholders and net transfers from Noncontrolling interest	$ 52,977	$ (9,985)

[1] The three months ended March 31, 2023 includes a net transfer of $ 1.0 million from Noncontrolling interest for share repurchases and common stock issuances related to employees' share-based compensation with a corresponding adjustment to Paid-in capital. This equity adjustment had no impact on earnings other than a resulting increase to the noncontrolling interest proportionate share of net income and a corresponding decrease to the proportionate share of net income attributable to Class A common shareholders.

As discussed above and in Note 13, in the three months ended March 31, 2023, we repurchased shares of our Class A Common Stock and issued shares of our Class A Common Stock related to the vesting of employees' share-based compensation resulting in a change in the proportionate share of Common Units held by the Company relative to Juniper. As such, we recognized an adjustment to the carrying amount of noncontrolling interest and a corresponding adjustment to Class A common shareholders' equity of $1.0 million for the three months ended March 31, 2023 to reflect the revised ownership percentage of total equity. See Note 2 for further discussion.

Note 13 – Share-Based Compensation and Other Benefit Plans

Share-Based Compensation

We reserved 4,424,600 shares of Class A Common Stock for issuance under the Ranger Oil Management Incentive Plan for share-based compensation awards. A total of 820,651 RSUs and 664,414 PRSUs have been granted to employees and directors through March 31, 2023.

We recognized expense attributable to the RSUs and PRSUs of $2.1 million and $0.9 million for the three months ended March 31, 2023 and 2022, respectively. We recognize share-based compensation expense as a component of general and administrative ("G&A") expenses in our condensed consolidated statements of operations.

Time-Vested Restricted Stock Units

The table below summarizes activity for the three months ended March 31, 2023 with respect to awarded RSUs:

	Time-Vested Restricted Stock Units		Weighted-Average Grant Date Fair Value
Balance at January 1, 2023	149,871	$	17.51
Granted	9,078	$	38.68
Vested	(43,015)	$	4.72
Forfeited	(1,176)	$	42.81
Balance at March 31, 2023	114,758	$	23.72

Compensation expense for RSUs is recognized on a straight-line basis over the applicable vesting period, which is generally over a three-year period. As of March 31, 2023, we had $1.6 million of unrecognized compensation cost attributable to RSUs. We expect that cost to be recognized over a weighted-average period of 1.49 years.

Performance-Based Restricted Stock Units

The table below summarizes activity for the three months ended March 31, 2023 with respect to awarded PRSUs:

	Performance Restricted Stock Units		Weighted-Average Grant Date Fair Value
Balance at January 1, 2023	440,100	$	29.87
Granted	—	$	—
Vested	—	$	—
Forfeited	(1,177)	$	58.87
Balance at March 31, 2023	438,923	$	29.87

Compensation expense for PRSUs with a market condition is being amortized ratably over three years for the 2022 and 2021 grants. For the 2020 and 2019 grants, compensation expense for the PRSUs with a market condition were amortized on a graded-vesting basis. The applicable period for the amortization of compensation ranges from less than one year to three years. Compensation expense for PRSUs with a performance condition is recognized ratably over three years when it is considered probable that the performance condition will be achieved and such grants are expected to vest. PRSUs with a market condition do not allow for the reversal of previously recognized expense, even if the market condition is not achieved and no shares ultimately vest.

The 2022 and 2021 PRSU grants contain performance measures of which 50% are based on the Company's return on average capital employed ("ROCE") relative to a defined peer group and 50% are based on the Company's absolute total shareholder return and total shareholder return ("TSR") relative to a defined peer group over the three-year performance period. The 2022 and 2021 PRSUs cliff vest from 0% to 200% of the original grant at the end of a three-year performance period based on satisfaction of the respective underlying conditions.

PRSUs granted in 2020 and 2019 vested at 92% of the original grant based on TSR relative to a defined peer group over the three-year performance period. As TSR is deemed a market condition, the grant-date fair value for the 2019, 2020 and a portion of the 2021 and 2022 PRSU grants was derived by using a Monte Carlo model. The table below presents ranges for the assumptions used in the Monte Carlo model for the PRSUs granted in the following periods:

	2022	2021 [1]	2020 [1]	2019
Expected volatility	134.98% to 138.75%	131.74% to 134.74%	101.32% to 117.71%	49.9 %
Dividend yield	0.0 %	0.0 %	0.0 %	0.0 %
Risk-free interest rate	2.59 %	0.22% to 0.29%	0.18% to 0.51%	1.66 %
Performance period	2022-2024	2021-2023	2020-2022	2020-2022

[1] One executive officer's inducement award originally granted in August 2020 was amended in April 2021 to conform vesting conditions to other PRSU awards granted in 2021. The Monte Carlo assumptions for both years are included above.

As of March 31, 2023, we had $6.5 million of unrecognized compensation cost attributable to PRSUs. We expect that cost to be recognized over a weighted-average period of 1.49 years.

Other Benefit Plans

We maintain the Ranger Oil Corporation and Affiliated Companies Employees 401(k) Plan (the "401(k) Plan"), a defined contribution plan, which covers substantially all of our employees. We recognized expense attributable to the 401(k) Plan of $0.3 million for the three months ended March 31, 2023 and $0.2 million for the three months ended March 31, 2022. The charges for the 401(k) Plan are included as a component of G&A expenses in our condensed consolidated statements of operations.

We maintain unqualified legacy defined benefit pension and defined benefit postretirement plans that cover a limited number of former employees that retired prior to January 1, 2000. The combined expense recognized with respect to these plans was less than $0.1 million for each of the three months ended March 31, 2023 and 2022, and is included as a component of Other, net in our condensed consolidated statements of operations.

Note 14 – Earnings Per Share

Basic net earnings (loss) per share is calculated by dividing the net income (loss) available to Class A common shareholders, excluding net income or loss attributable to Noncontrolling interest, by the weighted average common shares outstanding for the period.

In computing diluted earnings (loss) per share, basic net earnings (loss) per share is adjusted based on the assumption that dilutive RSUs and PRSUs have vested and outstanding Common Units (and shares of Class B Common Stock) held by the Noncontrolling interest in the Partnership are exchanged for common shares. Accordingly, our reported net income (loss) attributable to Class A common shareholders is adjusted due to the elimination of the Noncontrolling interest assuming exchange of the Common Units (and shares of Class B Common Stock) held by the Noncontrolling interest.

The following table provides a reconciliation of the components used in the calculation of basic and diluted earnings (loss) per share for the periods presented:

	Three Months Ended March 31,	
	2023	2022
Numerator:		
Net income (loss)	$ 113,791	$ (20,661)
Net (income) loss attributable to Noncontrolling interest	(61,792)	10,676
Net income (loss) attributable to Class A common shareholders for Basic EPS	51,999	(9,985)
Adjustment for assumed conversions and elimination of Noncontrolling interest net income (loss)	429	(10,676)
Net income (loss) attributable to Class A common shareholders for Diluted EPS	$ 52,428	$ (20,661)
Denominator:		
Weighted average shares outstanding used in Basic EPS	18,975	21,107
Effect of dilutive securities:		
Common Units and Class B Common Stock that are exchangeable for Class A Common Stock [1]	—	—
RSUs and PRSUs [1]	648	—
Weighted average shares outstanding used in Diluted EPS [1]	19,623	21,107

[1] For the three months ended March 31, 2023 and 2022, approximately 22.5 million potentially dilutive Common Units (and the associated 22.5 million Class B Common Stock) had the effect of being anti-dilutive and were excluded from the calculation of earnings per share. For the three months ended March 31, 2022, 0.6 million of RSUs and PRSUs had the effect of being anti-dilutive and were excluded from the calculation of earnings per share.

Note 15 – Subsequent Events

Dividends

On May 5, 2023, the Company's Board of Directors declared a cash dividend of $0.075 per share of Class A Common Stock, payable on May 30, 2023 to holders of record of Class A Common Stock as of the close of business on May 22, 2023.

Forward-Looking Statements

Certain statements contained herein that are not descriptions of historical facts are "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, (the "Exchange Act"). We use words such as "anticipate," "guidance," "assumptions," "projects," "estimates," "expects," "continues," "intends," "plans," "believes," "forecasts," "future," "potential," "may," "possible," "could" and variations of such words or similar expressions to identify forward-looking statements. Because such statements include risks, uncertainties and contingencies, actual results may differ materially from those expressed or implied by such forward-looking statements. These risks, uncertainties and contingencies include, but are not limited to, the following:

- risks and uncertainty related to our announced merger (the "Baytex Merger") with Baytex Energy Corp. ("Baytex"), including the risk that the conditions to the closing of the transaction are not satisfied and the additional risks discussed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2022;
- risks related to completed acquisitions, including the risk that the benefits of the acquisitions may not be fully realized or may take longer to realize than expected, and that management attention will be diverted to integration-related issues;
- the sustained market uncertainty with respect to, and volatility of commodity prices for, crude oil, natural gas liquids ("NGLs"), and natural gas;
- general economic conditions, including as a result of governmental actions to address elevated inflation levels caused by labor shortages, supply shortages and increased demand, and other inflationary pressures;
- the impact of world health events, economic slowdown, governmental actions, stay-at-home orders and interruptions to our operations or our customer's operations;
- our ability to satisfy our short-term and long-term liquidity needs, including our ability to generate sufficient cash flows from operations or to obtain adequate financing on favorable terms, including access to the capital markets, to fund our capital expenditures and meet working capital needs;
- our ability to access capital, including through lending arrangements and the capital markets, as and when desired;
- negative events or publicity adversely affecting our ability to maintain our relationships with our suppliers, service providers, customers, employees, and other third parties;
- plans, objectives, expectations and intentions contained in this report that are not historical;
- our ability to execute our business plan in volatile commodity price environments;
- our ability to develop, explore for, acquire and replace oil and gas reserves and sustain production;
- changes to our drilling and development program;
- our ability to generate profits or achieve targeted reserves in our development operations;
- our ability to meet guidance, market expectations and internal projections, including type curves;
- any impairments, write-downs or write-offs of our reserves or assets;
- the projected demand for and supply of oil, NGLs and natural gas;
- our ability to contract for drilling rigs, frac crews, materials, supplies and services at reasonable costs;
- our ability to declare dividends;
- our ability to renew or replace expiring contracts on acceptable terms;
- our ability to obtain adequate pipeline transportation capacity or other transportation for our oil and gas production at reasonable cost and to sell our production at, or at reasonable discounts to, market prices;
- the uncertainties inherent in projecting future rates of production for our wells and the extent to which actual production differs from that estimated in our proved oil and gas reserves;
- use of new techniques in our development, including choke management and longer laterals;
- drilling, completion and operating risks, including adverse impacts associated with well spacing and a high concentration of activity;
- our ability to compete effectively against other oil and gas companies;
- leasehold terms expiring before production can be established and our ability to replace expired leases;

- environmental obligations, costs and liabilities that are not covered by an effective indemnity or insurance;
- the timing of receipt of necessary regulatory permits;
- the effect of commodity and financial derivative arrangements with other parties and counterparty risk related to the ability of these parties to meet their future obligations;
- the occurrence of unusual weather or operating conditions, including force majeure events;
- our ability to retain or attract senior management and key employees;
- our reliance on a limited number of customers and a particular region for substantially all of our revenues and production;
- compliance with and changes in governmental regulations or enforcement practices, especially with respect to environmental, health and safety matters;
- physical, electronic and cybersecurity breaches;
- uncertainties and economic events relating to general domestic and international economic and political conditions, including political tensions or war;
- the impact and costs associated with litigation or other legal matters;
- sustainability initiatives; and
- other factors set forth in our periodic filings with the Securities and Exchange Commission, or SEC, including the risks set forth in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2022.

Additional information concerning these and other factors can be found in our press releases and public filings with the SEC. Many of the factors that will determine our future results are beyond the ability of management to control or predict. Readers should not place undue reliance on forward-looking statements, which reflect management's views only as of the date hereof. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these cautionary statements. We undertake no obligation to revise or update any forward-looking statements, or to make any other forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable law.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of the financial condition and results of operations of Ranger Oil Corporation and its consolidated subsidiaries ("Ranger," "Ranger Oil," the "Company," "we," "us" or "our") should be read in conjunction with our condensed consolidated financial statements and notes thereto included in Part I, Item 1, "Financial Statements." All dollar amounts presented in the tables that follow are in thousands unless otherwise indicated. Also, due to the combination of different units of volumetric measure, the number of decimal places presented and rounding, certain results may not calculate explicitly from the values presented in the tables. References to "quarters" represent the three months ended March 31, 2023 or 2022, as applicable.

Overview and Executive Summary

We are an independent oil and gas company focused on the onshore development and production of crude oil, NGLs, and natural gas. Our current operations consist of drilling unconventional horizontal development wells and operating our producing wells in the Eagle Ford Shale in South Texas.

Key Developments

Pending Baytex Merger

On February 27, 2023, we entered into the Agreement and Plan of Merger (the "Merger Agreement") with Baytex. Subject to the terms and conditions of the Merger Agreement, each share of our Class A Common Stock issued and outstanding immediately prior to the effective time of the consummation of the Baytex Merger (including shares of our Class A Common Stock to be issued in connection with the exchange of the Class B Common Stock and Common Units for Class A Common Stock), will be converted automatically into the right to receive: (i) 7.49 Baytex common shares and (ii) $13.31 in cash. The transaction was unanimously approved by the board of directors of each company and JSTX Holdings, LLC and Rocky Creek Resources, LLC delivered a support agreement to vote their outstanding shares in favor of the Baytex Merger. The Baytex Merger is expected to close in late second quarter or early third quarter of 2023, subject to the satisfaction of customary closing conditions, including the requisite shareholder and regulatory approvals.

Shareholder Returns

Share Repurchase Program

During the three months ended March 31, 2023, we repurchased 121,857 shares of our Class A Common Stock at a total cost of $4.8 million and average purchase prices of $39.52. We do not intend to repurchase additional shares pending closing of the Baytex Merger.

See Note 12 to the condensed consolidated financial statements included in Part I, Item 1, “Financial Statements” for additional information.

Dividends

On March 3, 2023, the Company’s Board of Directors declared a cash dividend of $0.075 per share of Class A Common Stock. The dividend was paid on March 30, 2023 to holders of record of Class A Common Stock as of the close of business on March 17, 2023. Additionally, on May 5, 2023, the Company’s Board of Directors declared a cash dividend of $0.075 per share of Class A Common Stock, payable on May 30, 2023 to holders of record of Class A Common Stock as of the close of business on May 22, 2023.

Industry Environment and Recent Operating and Financial Highlights

Commodity Price and Other Economic Conditions

As an oil and gas development and production company, we are exposed to a number of risks and uncertainties that are inherent to our industry.

There continues to be a high level of uncertainty around the volatility of energy supply and demand. Beginning with an announcement in April 2022 of production cuts which took effect in November 2022, the Organization of the Petroleum Exporting Countries (“OPEC”) and Russia (together with OPEC, “OPEC+”) changed its strategy from one which had seen gradually increasing production throughout most of 2022 to one of cutting production. In April 2023, OPEC+ announced a surprise oil output cut of approximately 1.16 million barrels of oil per day (“MMbbl/d”) bringing the total volume cuts by OPEC+ to over 3.66 MMbbl/d until the end of 2023. These shifts in OPEC+ production levels as well as the Russia-Ukraine war and related sanctions, which began in the first quarter of 2022, continue to contribute to volatility in commodity prices. During 2022 and through the first quarter of 2023, NYMEX West Texas Intermediate (“NYMEX WTI”) crude oil and NYMEX Henry Hub (“NYMEX HH”) natural gas prices ranged from over $120 per barrel (“bbl”) and over $9 per million British thermal units (“MMBtu”), respectively, to lows of approximately $67 per bbl and under $2 per MMBtu, respectively, due to oil supply shortage concerns and factors discussed above. Higher commodity prices, along with the global supply chain issues and other factors, have increased inflation, which has led or may lead to increased costs of services and certain materials necessary for our operations. Governmental actions to combat inflation, including the Inflation Reduction Act passed into law in August 2022 as well as interest rate hikes by the Federal Reserve and increased recession fears also continue to create pricing and economic volatility in the markets. The ultimate effect of these measures on inflation and overall energy supply and demand is uncertain at this time.

Our crude oil production is sold at a premium or deduct differential to the prevailing NYMEX WTI price. The differential reflects adjustments for location, quality and transportation and gathering costs, as applicable. All of our crude oil volumes are sold under Magellan East Houston (“MEH”) pricing, which historically has been at a premium to NYMEX WTI.

Similar to crude prices, natural gas prices remain volatile as a result of the Russia-Ukraine war and other factors, with NYMEX HH closing as low as $3.45 per MMBtu and as high as $9.85 per MMBtu during 2022. Subsequently, natural gas prices declined even further during 2023 with NYMEX HH closing as low as $1.93 per MMBtu. Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity, and supply and demand relationships in that region or locality. Similar to crude oil, our natural gas sold has a premium or deduct differential to the prevailing NYMEX HH price primarily due to adjustments for location and energy content of the natural gas. Location differentials result from variances in natural gas transportation costs based on the proximity of the natural gas to its major consuming markets that correspond with the ultimate delivery point as well as individual interaction of supply and demand.

A summary of these pricing differentials is provided in the discussion of "Results of Operations – Realized Differentials" that follows.

In addition to the volatility of commodity prices, we are subject to inflationary and other factors that have resulted in higher costs for products, materials and services that we utilize in both our capital projects and with respect to our operating expenses. We continue to work with vendors and other service providers to secure competitive pricing and fixed price terms whenever favorable in an effort to resist inflationary pressures. However, supply chain constraints may continue and exacerbate inflationary demands in the future.

Capital Expenditures, Development Progress and Production

As of March 31, 2023, we operated two drilling rigs and during the three months ended March 31, 2023, we incurred capital expenditures of approximately $148.9 million, of which $146.5 million was directed to drilling and completion projects. During the first quarter 2023, a total of 17 gross (15.4 net) wells were completed and turned to sales.

As of May 3, 2023, we had approximately 186,900 gross (163,000 net) acres in the Eagle Ford, net of expirations, of which approximately 95% is held by production.

Total sales volume for the first quarter 2023 was 4,386 thousand barrels of oil equivalent ("Mboe"), or 48,730 barrels of oil equivalent ("boe") per day, with approximately 73%, or 3,191 thousand barrels of oil ("Mbbl"), of sales volume from crude oil, 14% from NGLs and 13% from natural gas.

Commodity Hedging Program

As of May 3, 2023, we have hedged a portion of our estimated future crude oil, NGL and natural gas production from April 1, 2023 through the first half of 2024. The following table summarizes our net hedge position for the periods presented:

	2Q2023	3Q2023	4Q2023	1Q2024	2Q2024
NYMEX WTI Crude Swaps					
Average Volume Per Day (bbl)	2,400	2,807	2,657	462	462
Weighted Average Swap Price ($/bbl)	$ 54.26	$ 54.92	$ 54.93	$ 58.75	$ 58.75
NYMEX WTI Crude Collars					
Average Volume Per Day (bbl)	24,077	22,125	16,418	8,242	1,648
Weighted Average Purchased Put Price ($/bbl)	$ 67.89	$ 71.84	$ 71.24	$ 65.00	$ 65.00
Weighted Average Sold Call Price ($/bbl)	$ 79.10	$ 87.64	$ 86.25	$ 83.89	$ 81.45
NYMEX WTI Crude CMA Roll Basis Swaps					
Average Volume Per Day (bbl)		3,261			
Weighted Average Swap Price ($/bbl)		$ 0.88			
MEH WTI CMA Crude Differential Swaps					
Average Volume Per Day (bbl)	13,187				
Weighted Average Swap Price ($/bbl)	$ 2.03				
NYMEX HH Swaps					
Average Volume Per Day (MMBtu)	7,500				
Weighted Average Swap Price ($/MMBtu)	$ 3.690				
NYMEX HH Collars					
Average Volume Per Day (MMBtu)	11,538	11,413	11,413	11,538	11,538
Weighted Average Purchased Put Price ($/MMBtu)	$ 2.500	$ 2.500	$ 2.500	$ 2.500	$ 2.328
Weighted Average Sold Call Price ($/MMBtu)	$ 2.682	$ 2.682	$ 2.682	$ 3.650	$ 3.000
HSC Basis Swaps					
Average Volume Per Day (MMBtu)	19,038	11,413	11,413		
HSC Basis Average Fixed Price ($/MMBtu)	$ (0.153)	$ (0.153)	$ (0.153)		
HSC Index Swaps					
Average Volume Per Day (MMBtu)	12,720				
HSC Basis Average Fixed Price ($/MMBtu)	($0.025)				
OPIS Mt. Belvieu Ethane Swaps					
Average Volume per Day (gal)	98,901	34,239	34,239	34,615	
Weighted Average Fixed Price ($/gal)	$ 0.2288	$ 0.2275	$ 0.2275	$ 0.2275	

Results of Operations

The following table sets forth certain historical summary operating and financial statistics for the periods presented:

	Three Months Ended		
	March 31, 2023	December 31, 2022	March 31, 2022
Total sales volume (Mboe) [1]	4,386	4,069	3,398
Average daily sales volume (boe/d) [1]	48,730	44,227	37,752
Crude oil sales volume (Mbbl) [1]	3,191	2,916	2,428
Crude oil sold as a percent of total [1]	73 %	72 %	71 %
Product revenues	$ 257,431	$ 268,455	$ 255,599
Crude oil revenues	$ 236,932	$ 240,397	$ 226,732
Crude oil revenues as a percent of total	92 %	90 %	89 %
Realized prices:			
Crude oil ($/bbl)	$ 74.25	$ 82.46	$ 93.38
NGLs ($/bbl)	$ 20.08	$ 21.75	$ 33.40
Natural gas ($/Mcf)	$ 2.36	$ 4.53	$ 4.32
Aggregate ($/boe)	$ 58.70	$ 65.98	$ 75.23
Realized prices, including effects of derivatives, net [2]			
Crude oil ($/bbl)	$ 70.80	$ 76.43	$ 74.00
NGLs ($/bbl)	$ 20.08	$ 21.17	$ 33.40
Natural gas ($/Mcf)	$ 3.69	$ 2.76	$ 3.96
Aggregate ($/boe)	$ 57.26	$ 60.15	$ 61.08
Production and lifting costs:			
Lease operating ($/boe)	$ 6.84	$ 6.06	$ 5.33
Gathering, processing and transportation ($/boe)	$ 2.32	$ 2.27	$ 2.66
Production and ad valorem taxes ($/boe)	$ 3.66	$ 3.63	$ 3.87
General and administrative ($/boe) [3]	$ 2.89	$ 2.64	$ 2.88
Depreciation, depletion and amortization ($/boe)	$ 19.45	$ 17.96	$ 14.98

[1] All volumetric statistics presented above represent volumes of commodity production that were sold during the periods presented. Volumes of crude oil physically produced in excess of volumes sold are placed in temporary storage to be sold in subsequent periods.

[2] Realized prices, including effects of derivatives, net is a non-GAAP measure (see discussion and reconciliation to GAAP measure below in "*Results of Operations – Effects of Derivatives*" that follows).

[3] Includes combined amounts of $1.08, $0.07 and $0.79 per boe for the three months ended March 31, 2023 , December 31, 2022 and March 31, 2022, respectively, attributable to share-based compensation and certain special charges, comprised of (i) acquisition, integration and strategic transaction costs attributable to the pending Baytex Merger and costs incurred during the first quarter of 2023 attributable to our 2022 acquisitions, (ii) organizational restructuring costs and costs incurred during the fourth quarter of 2022 attributable to our 2022 acquisitions, and (iii) acquisition, integration and strategic transaction costs including costs incurred in the first quarter of 2022 attributable to the acquisition of Lonestar Resources US Inc. ("Lonestar Acquisition"). For further details, see the discussion of *"Results of Operations - General and Administrative"* that follows.

Sequential Quarterly Analysis

The following summarizes our key operating and financial highlights for the three months ended March 31, 2023 with comparison to the three months ended December 31, 2022. The year-over-year highlights for the quarterly periods ended March 31, 2023 and 2022 are addressed in further detail in the discussions that follow below in *Year over Year Analysis of Operating and Financial Results*.

- Daily sales volume and total sales volume increased 10% to 48,730 boe/d and 8% to 4,386 Mboe, respectively, for the three months ended March 31, 2023 compared to 44,227 boe/d and 4,069 Mboe for the three months ended December 31, 2022. The increase was primarily due to 15.4 net wells turned to sales during the first quarter of 2023.
- Product revenues decreased 4% to $257.4 million from $268.5 million as a result of 11% lower aggregate realized prices offset by 8% higher total sales volumes. Crude oil revenues were 1% lower due to 10% lower realized prices, or $26.2 million, offset by 9% higher crude oil sales volume, or $22.7 million. NGL revenues were 8% lower due to 8% lower realized prices, or $1.0 million and nominally lower total sales volume, or $0.1 million. Natural gas revenues were 44% lower as a result of 48% lower realized prices, partially offset by 8% higher volume for an overall decrease of $6.5 million.
- Lease operating expenses (“LOE”) increased on an absolute basis to $30.0 million from $24.7 million primarily driven by $2.8 million higher repairs and maintenance costs, $0.9 million of higher equipment rental costs, $0.7 million of increased water disposal costs and $0.4 million higher field labor costs, and overall cost inflation. LOE increased on a per unit basis to $6.84 from $6.06 due to the aforementioned higher costs slightly offset with the effects of the 8% higher sales volume discussed above.
- Gathering, processing and transportation expenses (“GPT”) increased on an absolute and per unit basis to $10.2 million and $2.32 per boe, respectively, from $9.2 million and $2.27 per boe, respectively, due to higher GPT costs from higher crude oil and natural gas volumes.
- Production and ad valorem taxes increased on an absolute basis to $16.0 million from $14.8 million and increased on a per unit basis to $3.66 per boe from $3.63 per boe due primarily to higher estimated ad valorem tax assessments in 2023, resulting from the property acquisitions and development that occurred throughout 2022 and higher prior year oil prices which are used in the valuation of our producing properties. This increase was partially offset by a decrease in production taxes resulting from the decline in realized commodity prices.
- General and administrative expenses (“G&A”) increased on an absolute and per unit basis to $12.7 million and $2.89 per boe from $10.7 million and $2.64 per boe, respectively, due primarily to $2.6 million of transaction costs incurred related to the Baytex Merger, partially offset by $0.7 million in lower compensation costs.
- Depreciation, depletion and amortization (“DD&A”) increased on an absolute and per unit basis to $85.3 million and $19.45 per boe during the first quarter 2023 from $73.1 million and $17.96 per boe during the fourth quarter 2022 primarily due to increased future development costs associated with proved reserve additions that were at a higher relative cost per boe as compared to fourth quarter of 2022.

Year over Year Analysis of Operating and Financial Results

Sales Volume

The following tables set forth a summary of our total and average daily sales volumes by product for the periods presented:

Total Sales Volume [1]	Three Months Ended March 31, 2023	2022	Change	% Change
Crude oil (Mbbl)	3,191	2,428	763	31 %
NGLs (Mbbl)	605	501	104	21 %
Natural gas (MMcf)	3,535	2,810	725	26 %
Total (Mboe)	4,386	3,398	988	29 %

Average Daily Sales Volume [1]	Three Months Ended March 31, 2023	2022	Change	% Change
Crude oil (bbl/d)	35,458	26,980	8,478	31 %
NGLs (bbl/d)	6,725	5,568	1,157	21 %
Natural gas (MMcf/d)	39	31	8	26 %
Total (boe/d)	48,730	37,752	10,978	29 %

[1] All volumetric statistics represent volumes of commodity production that were actually sold during the periods presented. Volumes of crude oil physically produced in excess of volumes sold are placed in temporary storage to be sold in subsequent periods.

Total sales volume increased 29% during the three month period in 2023 when compared to the corresponding period in 2022 as a result of acquisitions that closed subsequent to the first quarter of 2022 and increased drilling activity.

Approximately 73% of total sales volume during the three month period in 2023 was attributable to crude oil compared to approximately 71% during the corresponding period in 2022.

Product Revenues and Prices

The following tables set forth a summary of our revenues and prices per unit of volume by product for the periods presented:

Total Product Revenues	Three Months Ended March 31, 2023	2022	Change	% Change
Crude oil	$ 236,932	$ 226,732	$ 10,200	4 %
NGLs	12,154	16,740	(4,586)	(27) %
Natural gas	8,345	12,127	(3,782)	(31) %
Total	$ 257,431	$ 255,599	$ 1,832	1 %

Realized Prices ($ per unit of volume)	Three Months Ended March 31, 2023	2022	Change	% Change
Crude oil	$ 74.25	$ 93.38	$ (19.13)	(20) %
NGLs	$ 20.08	$ 33.40	$ (13.32)	(40) %
Natural gas	$ 2.36	$ 4.32	$ (1.96)	(45) %
Total	$ 58.70	$ 75.23	$ (16.53)	(22) %

The following table provides an analysis of the changes in our revenues for the periods presented:

	Three Months Ended March 31, 2023 vs. 2022 Revenue Variance Due to		
	Volume	Price	Total
Crude oil	$ 71,246	$ (61,046)	$ 10,200
NGLs	3,479	(8,065)	(4,586)
Natural gas	3,130	(6,912)	(3,782)
	$ 77,855	$ (76,023)	$ 1,832

Our product revenues during the three month period in 2023 increased compared to the corresponding period in 2022 due to an increase in volumes across all commodities as discussed above, with an overall increase in Mboe of 29% for three month period in 2023. This increase was partially offset by a decrease to the NYMEX WTI benchmark price of 20% for the three month period in 2023 as compared to the corresponding period in 2022 due to macroeconomic factors and volatility in the global commodity markets, as well as supply concerns resulting from the Russia-Ukraine war that drove prices up in the first quarter of 2022.

Realized Differentials

The following table reconciles our realized price differentials from average NYMEX-quoted prices for WTI crude oil and HH natural gas for the periods presented:

	Three Months Ended March 31,			
	2023	2022	Change	% Change
Average WTI prices ($/bbl)	$ 75.99	$ 95.01	$ (19.02)	(20) %
Realized differential to WTI	(1.74)	(1.63)	(0.11)	(7) %
Realized crude oil prices ($/bbl)	$ 74.25	$ 93.38	$ (19.13)	(20) %
Average HH prices ($/MMBtu)	$ 2.68	$ 4.60	$ (1.92)	(42) %
Realized differential to HH	(0.32)	(0.28)	(0.04)	(14) %
Realized natural gas prices ($/Mcf)	$ 2.36	$ 4.32	$ (1.96)	(45) %

Our differential to NYMEX WTI was less favorable for the three month period in 2023 compared to the corresponding period in 2022 primarily due to a lower MEH to NYMEX WTI premium, partially offset by lower transportation and location deducts. Our differential to NYMEX HH was less favorable for the three month period in 2023 as compared to the corresponding period in 2022 due primarily to higher location basis differentials. See also the discussion of *Commodity Price and Other Economic Conditions* in the Overview above.

Effects of Derivatives

We present realized prices for crude oil and natural gas, as adjusted for the effects of derivatives, net as we believe these measures are useful to management and stakeholders in determining the effectiveness of our price-risk management program that is designed to reduce the volatility associated with our operations. Realized prices for crude oil and natural gas, as adjusted for the effects of derivatives, net, are supplemental financial measures that are not prepared in accordance with generally accepted accounting principles (“GAAP”).

The following table presents the calculation of our non-GAAP realized prices for crude oil and natural gas, as adjusted for the effects of derivatives, net and reconciles to realized prices for crude oil and natural gas determined in accordance with GAAP:

	Three Months Ended March 31, 2023	Three Months Ended March 31, 2022	Change	% Change
Realized crude oil prices ($/bbl)	$ 74.25	$ 93.38	$ (19.13)	(20) %
Effects of derivatives, net ($/bbl)	(3.45)	(19.38)	15.93	82 %
Crude oil realized prices, including effects of derivatives, net ($/bbl)	$ 70.80	$ 74.00	$ (3.20)	(4) %
Realized natural gas prices ($/Mcf)	$ 2.36	$ 4.32	$ (1.96)	(45) %
Effects of derivatives, net ($/Mcf)	1.33	(0.36)	1.69	NM
Natural gas realized prices, including effects of derivatives, net ($/Mcf)	$ 3.69	$ 3.96	$ (0.27)	(7) %

NM - percentage change not meaningful

Effects of derivatives, net include, as applicable to the period presented: (i) current period commodity derivative settlements; (ii) the impact of option premiums paid or received in prior periods related to current period production; (iii) the impact of prior period cash settlements of early-terminated derivatives originally designated to settle against current period production; (iv) the exclusion of option premiums paid or received in current period related to future period production; and (v) the exclusion of the impact of current period cash settlements for early-terminated derivatives originally designated to settle against future period production.

Other Operating Income, Net

Other operating income, net generally includes fees for marketing and water disposal services that we charge to third parties, net of related expenses, as well as other miscellaneous revenues and credits attributable to our current operations and gains and losses on the sale or disposition of assets other than our oil and gas properties. In addition, charges attributable to credit losses associated with our trade and joint venture partner receivables are netted within this caption.

The following table sets forth the total Other operating income, net recognized for the periods presented:

	Three Months Ended March 31, 2023	Three Months Ended March 31, 2022	Change	% Change
Other operating income, net	$ 717	$ 856	$ (139)	(16) %

Other operating income, net decreased primarily due to a loss on sales of field materials in the three month period in 2023 compared to a gain on sales of field materials in the three month period in 2022. Additionally, marketing fees were lower in the three month period in 2023 as compared to the corresponding period in 2022, primarily due to lower commodity-based pricing, partially offset by higher saltwater disposal income.

Lease Operating Expenses

LOE includes costs that we incur to operate our producing wells and field operations. The most significant costs include compression for gas lift, chemicals, water disposal, repairs and maintenance, including down-hole repairs, field labor, equipment rentals, utilities and supplies, among others.

The following table sets forth our LOE for the periods presented:

	Three Months Ended March 31, 2023	Three Months Ended March 31, 2022	Change	% Change
Lease operating	$ 29,990	$ 18,102	$ 11,888	66 %
Per unit ($/boe)	$ 6.84	$ 5.33	$ 1.51	28 %

LOE increased on an absolute basis and per unit basis during three month period in 2023 as compared to the corresponding period in 2022 due primarily to $5.1 million higher repairs and maintenance costs, $2.0 million of increased water disposal costs, $1.5 million of higher equipment rental costs, $1.5 million of higher compression costs and $0.6 million higher chemicals costs, driven in part by higher sales volume from new wells brought online, coupled with the continued impacts of inflation.

Gathering, Processing and Transportation

GPT expense includes costs that we incur to gather and aggregate our crude oil and natural gas production from our wells and deliver them via pipeline or truck to a central delivery point, downstream pipelines or processing plants, and blend or process, as necessary, depending upon the type of production and the specific contractual arrangements that we have with the applicable midstream operators. In addition, GPT expense includes short-term rental charges for crude oil storage tanks.

The following table sets forth our GPT expense for the periods presented:

	Three Months Ended March 31, 2023	Three Months Ended March 31, 2022	Change	% Change
GPT	$ 10,180	$ 9,040	$ 1,140	13 %
Per unit ($/boe)	$ 2.32	$ 2.66	$ (0.34)	(13) %

GPT expense increased on an absolute basis during the three month period in 2023 as compared to the corresponding period in 2022 due primarily to the impact of asset acquisitions that closed subsequent to the first quarter of 2022, which contributed to the 26% higher natural gas sales volumes and 31% higher crude oil sales volumes for the three month period in 2023. Additionally, for certain of our crude oil volumes gathered, our rate includes an adjustment based on NYMEX WTI prices. As crude oil prices increase, up to a cap of $90 per bbl, the gathering rate escalates. As such, with the lower prices during the three month period in 2023 as compared to the corresponding period in 2022, we incurred lower gathering costs associated with these volumes, which partially offset the increase in GPT expense during the three month period in 2023. The lower rate associated with these volumes, along with the 29% increase in total sales volumes in 2023 resulted in lower GPT expense on a per unit basis for the three month period in 2023 compared to the corresponding period in 2022.

Production and Ad Valorem Taxes

Production or severance taxes represent taxes imposed by the states in which we operate for the removal of resources including crude oil, NGLs and natural gas and are based on current period commodity prices. Ad valorem taxes represent taxes imposed by certain jurisdictions, primarily counties, in which we operate, based on the assessed value of our operating properties. The assessments for ad valorem taxes are generally based on prior year published index prices.

The following table sets forth our production and ad valorem taxes for the periods presented:

	Three Months Ended March 31, 2023	Three Months Ended March 31, 2022	Change	% Change
Production taxes	$ 11,864	$ 11,570	$ 294	3 %
Ad valorem taxes	4,178	1,570	2,608	166 %
Production and ad valorem taxes	$ 16,042	$ 13,140	$ 2,902	22 %
Per unit ($/boe)	$ 3.66	$ 3.87	$ (0.21)	(5) %
Production tax rate as a percent of product revenues	4.6 %	4.5 %	0.1 %	2 %

Production and ad valorem taxes increased on an absolute basis during the three month period in 2023 as compared to the corresponding period in 2022 primarily due to higher estimated ad valorem tax assessments driven by an increase in properties acquired, or developed, subsequent to the first quarter of 2022, and higher prior year oil prices which impact the overall valuation of our producing properties. Production and ad valorem taxes decreased on a per unit basis during the three month period in 2023 as compared to the corresponding period in 2022 primarily due to higher sales volumes from asset acquisitions that closed subsequent to the first quarter of 2022 and decreases in aggregate commodity sales prices, partially offset by higher ad valorem taxes.

General and Administrative

Our G&A expenses include employee compensation, benefits and other related costs for our corporate management and governance functions, rent and occupancy costs for our corporate facilities, insurance, and professional fees and consulting costs supporting various corporate-level functions, among others. In order to facilitate a meaningful discussion and analysis of our results of operations with respect to G&A expenses, we have disaggregated certain costs into three components as presented in the table below. Primary G&A encompasses all G&A costs except share-based compensation and certain special charges that are generally attributable to stand-alone transactions or corporate actions that are not otherwise in the normal course.

The following table sets forth the components of our G&A expenses for the periods presented:

	Three Months Ended March 31, 2023	Three Months Ended March 31, 2022	Change	% Change
Primary G&A expenses	$ 7,951	$ 7,112	$ 839	12 %
Share-based compensation	2,051	924	1,127	122 %
Special charges:				
Acquisition/integration and strategic transaction costs	2,666	1,743	923	53 %
Total G&A expenses	$ 12,668	$ 9,779	$ 2,889	30 %
Per unit ($/boe)	$ 2.89	$ 2.88	$ 0.01	— %
Per unit ($/boe) excluding share-based compensation and other special charges identified above	$ 1.81	$ 2.09	$ (0.28)	(13) %

Our total G&A expenses were higher on an absolute and per unit basis during the three month period in 2023 when compared to the corresponding period in 2022 due primarily to higher transaction costs in the three month period in 2023 associated with the Baytex Merger compared to transaction costs in the three month period in 2022 associated with the Lonestar Acquisition, as well as higher share-based compensation cost in 2023.

Our primary G&A expenses increased on an absolute basis during the three month period in 2023 as compared to the corresponding period in 2022 due primarily to higher consulting and professional fees, partially offset by lower compensation costs. Primary G&A expenses decreased on a per unit basis due to higher overall sales volumes in 2023.

Share-based compensation charges during the periods presented are attributable to the amortization of compensation cost, net of forfeitures, associated with the grants of time-vested restricted stock units (“RSUs”), and performance-based restricted stock units (“PRSUs”). The grants of RSUs and PRSUs are described in greater detail in Note 13 to the condensed consolidated financial statements included in Part I, Item 1, “Financial Statements.” All of our share-based compensation represents non-cash expenses.

Depreciation, Depletion and Amortization

DD&A expense includes charges for the allocation of property costs based on the volume of production, depreciation of fixed assets other than oil and gas assets as well as the accretion of our asset retirement obligations.

The following table sets forth total and per unit costs for DD&A expense for the periods presented:

	Three Months Ended March 31, 2023	Three Months Ended March 31, 2022	Change	% Change
DD&A expense	$ 85,303	$ 50,893	$ 34,410	68 %
DD&A rate ($/boe)	$ 19.45	$ 14.98	$ 4.47	30 %

DD&A expense increased on an absolute and per unit basis during the three month period in 2023 as compared to the corresponding period in 2022. Higher production volume provided for an increase of $14.8 million and a higher DD&A rate resulted in an increase of $19.6 million for the three month period in 2023. The higher DD&A rate in 2023 is primarily due to the asset acquisitions that closed subsequent to the first quarter of 2022 and increased future development costs associated with proved reserve additions, which contributed to an increase in our total proved reserves at a higher relative cost per boe as compared to the corresponding period in 2022.

Interest Expense

Interest expense includes charges for outstanding borrowings under the Credit Facility derived from internationally recognized interest rates with a premium based on our credit profile and the level of credit outstanding and the contractual rate associated with the 9.25% Senior Notes due 2026. Also included are the amortization of issuance costs capitalized attributable to the Credit Facility and the 9.25% Senior Notes due 2026 and accretion of original issue discount ("OID") on the 9.25% Senior Notes due 2026.

In addition, we are assessed certain fees for the overall credit commitments provided to us as well as fees for credit utilization and letters of credit. These costs are partially offset by interest amounts that we capitalize on unproved property costs while we are engaged in the evaluation of projects for the underlying acreage.

The following table summarizes the components of our interest expense for the periods presented:

	Three Months Ended March 31,			
	2023	2022	Change	% Change
Interest on borrowings and related fees	$ 14,679	$ 10,957	$ 3,722	34 %
Accretion of original issue discount	176	160	16	10 %
Amortization of debt issuance costs	768	640	128	20 %
Capitalized interest	(905)	(1,060)	155	(15) %
Total interest expense, net of capitalized interest	$ 14,718	$ 10,697	$ 4,021	38 %

The increase in interest expense during the three month period in 2023 is primarily attributable to interest incurred in the amount of $9.2 million for the 9.25% Senior Notes due 2026 and $5.1 million for the Credit Facility compared to interest incurred in the corresponding period in 2022 of $8.8 million for the 9.25% Senior Notes due 2026 and $1.7 million for the Credit Facility, as well as increased amortization of OID and debt issuance costs in 2023 compared to the corresponding period in 2022. Additionally, interest expense increased due to less capitalized interest during the three month period in 2023 driven by a lower unproved property balance, partially offset by the increase in capitalized interest due to higher overall weighted-average interest rates in 2023 as compared to the corresponding period in 2022.

Derivatives

The gains and losses for our derivatives portfolio reflect changes in the fair value attributable to changes in market values relative to our hedged commodity prices and interest rates.

The following table summarizes the gains and losses attributable to our commodity derivatives portfolio and interest rate swaps for the periods presented:

	Three Months Ended March 31,			
	2023	2022	Change	% Change
Commodity derivative gains (losses)	$ 25,658	$ (167,970)	$ 193,628	(115)%
Interest rate swap gains	—	83	(83)	(100)%
Total	$ 25,658	$ (167,887)	$ 193,545	(115)%

In the three month period in 2023, commodity prices were significantly lower on an average aggregate basis than those during the corresponding period in 2022. The derivative gains in the three month period in 2023 reflect the increase in the mark-to-market values consistent with the decreases in prices attributable to open positions for this period. The derivative losses in the three month period in 2022 reflect the decline in the mark-to-market values consistent with the increase in prices attributable to open positions in the period. Realized settlement payments, net for crude oil and natural gas derivatives were $7.4 million for the three month period in 2023 and $28.5 million during the three month period in 2022. Through May 2022, we hedged a portion of our exposure to variable interest rates associated with our Credit Facility. As of March 31, 2023, we did not have any interest rate derivatives. We paid $0.9 million of net settlements from our interest rate swaps for the three month period in 2022.

Income Taxes

Income taxes represent our income tax provision as determined in accordance with generally accepted accounting principles. It considers taxes attributable to our obligations for federal taxes under the Internal Revenue Code as well as to the various states in which we operate, primarily Texas, or otherwise have continuing involvement.

The following table summarizes our income tax provision for the periods presented:

	Three Months Ended March 31,			
	2023	2022	Change	% Change
Income tax (expense) benefit	$ (991)	$ 189	$ (1,180)	(624)%
Effective tax rate	0.9 %	0.9 %	— %	— %

The income tax provision resulted in an expense of $1.0 million for the three month period in 2023. The federal portion was fully offset by an adjustment to the valuation allowance against our net deferred tax assets resulting in an effective tax rate of 0.9%, which is fully attributable to the State of Texas. Our net deferred income tax liability balance of $7.0 million as of March 31, 2023 is also fully attributable to the State of Texas and primarily related to property.

The income tax provision resulted in a benefit of $0.2 million for the three month period in 2022. The federal portion was fully offset by an adjustment to the valuation allowance against our net deferred tax assets resulting in an effective tax rate of 0.9%, which was fully attributable to the State of Texas.

Liquidity and Capital Resources

Liquidity

Our primary sources of liquidity include our cash on hand, cash provided by operating activities and borrowings under the Credit Facility. As of March 31, 2023, we had liquidity of $271.4 million, comprised of cash and cash equivalents of $12.4 million and availability under our Credit Facility of $259.0 million (factoring in letters of credit). The Credit Facility provides us up to $1.0 billion in borrowing commitments. The current borrowing base under the Credit Facility is $950.0 million with aggregate elected commitments of $500.0 million.

Our cash flows from operating activities are subject to significant volatility due to changes in commodity prices for crude oil, NGLs and natural gas, as well as variations in our production. The prices for these commodities are driven by a number of factors beyond our control, including global and regional product supply and demand, weather, product distribution, refining and processing capacity and other supply chain dynamics, among other factors. All of these factors have been impacted by the volatility and uncertainty in the global economic markets stemming from the Russia-Ukraine war, OPEC+ production decisions and related instability in the global energy markets, as well as inflationary pressures and recession fears that impact demand. In order to mitigate this volatility, we utilize derivative contracts with a number of financial institutions, all of which are participants in our Credit Facility, hedging a portion of our estimated future crude oil, NGLs and natural gas production through the first half of 2024. The level of our hedging activity and duration of the financial instruments employed depends on our desired cash flow protection, available hedge prices, the magnitude of our capital program and our operating strategy.

From time to time and under market conditions that we believe are favorable to us, we may consider capital market transactions, including the offering of debt and equity securities. We maintain an effective shelf registration statement to allow for optionality.

Capital Resources

Based upon current price and production expectations, we believe that our cash on hand, cash from operating activities and borrowings under our Credit Facility, as necessary, will be sufficient to fund our capital spending and operations for at least the next twelve months; however, future cash flows are subject to a number of variables including the length and magnitude of the current global economic uncertainties associated with continued volatility and related instability in the global energy markets. We plan to fund our 2023 capital expenditures and our operations primarily with cash on hand, cash from operating activities and, to the extent necessary, supplemental borrowings under the Credit Facility.

Additionally, we have other obligations primarily consisting of our outstanding debt principal and interest obligations, derivative instruments, service agreements, operating leases, and asset retirement obligations, all of which are customary in our business. See related notes to the condensed consolidated financial statements included in Part I, Item 1, "Financial Statements" for more details regarding these obligations. The Partnership is also required in certain circumstances to make certain tax distributions to its partners, which may impact cash flow from operations for the Company, as discussed below under "Tax Distributions."

Dividends

On March 3, 2023, the Company's Board of Directors declared a cash dividend of $0.075 per share of Class A Common Stock. The dividend was paid on March 30, 2023 to holders of record of Class A Common Stock as of the close of business on March 17, 2023. In connection with any dividend, Ranger's operating subsidiary will also make a corresponding distribution to its common unitholders. During the first quarter of 2023, the dividend to the holders of our Class A Common Stock and distribution to common unitholders totaled $3.1 million in the aggregate. Additionally, on May 5, 2023, the Company's Board of Directors declared a cash dividend of $0.075 per share of Class A Common Stock, payable on May 30, 2023 to holders of record of Class A Common Stock as of the close of business on May 22, 2023. We expect to fund dividends and distributions from available working capital and cash provided by operating activities.

Share Repurchase Program

In April 2022, we announced that the Board of Directors approved a share repurchase program under which we were authorized to repurchase up to $100 million of outstanding Class A Common Stock through March 31, 2023. Subsequently on July 7, 2022, the Board of Directors authorized an increase in the share repurchase program from $100 million to $140 million and extended the term of the program through June 30, 2023. We do not intend to repurchase additional shares pending closing of the Baytex Merger.

On August 16, 2022, the Inflation Reduction Act was signed into law and imposes a 1% excise tax on the repurchase of stock by publicly traded U.S. corporations. The excise tax is effective for stock repurchases after December 31, 2022. Based on total share repurchases of $4.8 million during the three months ended March 31, 2023, we recognized less than $0.1 million of additional cost within Paid-in capital associated with the excise tax for these share repurchases. We do not anticipate this new excise tax will materially impact our results of operations and cash flows.

Tax Distributions

Under its partnership agreement, the Partnership is required to make distributions to all of its limited partners pro rata on a quarterly basis and in such amounts as necessary to enable the Company to timely satisfy all of its U.S. federal, state and local and non-U.S. tax liabilities. Additionally, the Partnership is required to make advances to its non-corporate partners in an amount sufficient to enable such partner to timely satisfy its U.S. federal, state and local and non-U.S. tax liabilities (a "Tax Advance"). Any such Tax Advance will be treated as an advance against and, therefore, reduce any future distributions that such partner is otherwise entitled to receive. The Company's cash flow from operations and ability to pay cash dividends to our stockholders could be adversely impacted as a result of such cash distributions. Whether and how much Tax Advances are required to be paid is dependent upon the amount and timing of taxable income generated in the future that is allocable to partners and the federal tax rates then applicable. At this time, we are unable to assess whether the Partnership will be required to make Tax Advances for the year ending December 31, 2023 or in future years.

Cash Flows

The following table summarizes our cash flows for the periods presented:

	Three Months Ended March 31,	
	2023	2022
Net cash provided by operating activities	$ 160,249	$ 133,835
Net cash used in investing activities	(171,017)	(70,517)
Net cash provided by (used in) financing activities	15,530	(80,641)
Net increase (decrease) in cash and cash equivalents	$ 4,762	$ (17,323)

Cash Flows from Operating Activities. The increase of $26.4 million in net cash provided by operating activities for the three months ended March 31, 2023 compared to the corresponding period in 2022 was primarily attributable to $22.1 million lower net payments for commodity derivatives settlements and premiums and a decrease in cash outflows due to the timing of working capital payments and receipts, partially offset by $51.5 million decrease in operating income.

Cash Flows from Investing Activities. Our cash payments for capital expenditures were higher during the three months ended March 31, 2023 as compared to the corresponding period in 2022 due primarily to significantly increased drilling and completions activities in 2023 coupled with the current economic impacts of inflation and higher costs.

The following table sets forth costs related to our capital expenditures program for the periods presented:

	Three Months Ended March 31,	
	2023	2022
Drilling and completion	$ 146,484	$ 82,794
Lease acquisitions, land-related costs, and geological and geophysical (seismic) costs	3,129	665
Pipeline, gathering facilities and other equipment, net [1]	(746)	2
Total capital expenditures incurred	$ 148,867	$ 83,461

[1] Includes certain capital charges to our working interest partners for completion services.

The following table reconciles the total costs of our capital expenditures program with the net cash paid for capital expenditures as reported in our condensed consolidated statements of cash flows for the periods presented:

	Three Months Ended March 31,	
	2023	2022
Total capital expenditures program costs (from above)	$ 148,867	$ 83,461
Decrease (increase) in accounts payable for capital items and accrued capitalized costs	22,408	(9,361)
Net purchases of tubular inventory and well materials [1]	(2,300)	3,587
Prepayments for drilling and completion services, net of (transfers)	17	(8,964)
Capitalized internal labor, capitalized interest and other	2,472	2,450
Total cash paid for capital expenditures	$ 171,464	$ 71,173

[1] Includes purchases made in advance of drilling.

Cash Flows from Financing Activities. During the three months ended March 31, 2023, we had borrowings of $156.0 million and repayments of $131.0 million under the Credit Facility, $4.8 million of share repurchases, $1.7 million of distributions to common unitholders and $1.4 million of dividends paid to the holders of our Class A Common Stock. During the three months ended March 31, 2022, we had borrowings of $50.0 million and repayments of $130.0 million under the Credit Facility.

Capitalization

The following table summarizes our total capitalization as of the dates presented:

	March 31, 2023	December 31, 2022
Credit Facility	$ 240,000	$ 215,000
9.25% Senior Notes due 2026, net	389,480	388,839
Other	—	238
Total debt, net	629,480	604,077
Total equity	1,163,601	1,057,022
Total capitalization	$ 1,793,081	$ 1,661,099
Debt as a % of total capitalization	35 %	36 %

Credit Facility. As of March 31, 2023, the Credit Facility had a $1.0 billion revolving commitment and a $950 million borrowing base, with aggregate elected commitments of $500 million and a $25 million sublimit for the issuance of letters of credit. The borrowing base under the Credit Facility is redetermined semi-annually, generally in the Spring and Fall of each year. Additionally, we and the Credit Facility lenders may, upon request, initiate a redetermination at any time during the six-month period between scheduled redeterminations. The Credit Facility is available to us for general corporate purposes including working capital. We had $1.0 million in letters of credit outstanding as of both March 31, 2023 and December 31, 2022. The maturity date under the Credit Facility is October 6, 2025.

The outstanding borrowings under the Credit Facility bear interest at a rate equal to, at our option, either (a) a customary reference rate plus an applicable margin ranging from 1.50% to 2.50%, determined based on the utilization level under the Credit Facility or (b) a term Secured Overnight Financing Rate ("SOFR") reference rate, plus an applicable margin ranging from 2.50% to 3.50%, determined based on the utilization level under the Credit Facility. Interest on reference rate borrowings is payable quarterly in arrears and is computed on the basis of a year of 365/366 days, and interest on SOFR borrowings is payable every one, three or six months, at our election, and is computed on the basis of a year of 360 days. At March 31, 2023, the actual weighted-average interest rate on the outstanding borrowings under the Credit Facility was 7.67%. Unused commitment fees are charged at a rate of 0.50%.

The following table summarizes our borrowing activity under the Credit Facility for the periods presented:

	Borrowings Outstanding			
	End of Period	Weighted-Average	Maximum	Weighted-Average Rate
Three months ended March 31, 2023	$ 240,000	$ 262,633	$ 295,000	7.81 %

The Credit Facility is guaranteed by all of the subsidiaries of the borrower (the "Guarantor Subsidiaries"), except for Boland Building, LLC. The guarantees under the Credit Facility are full and unconditional and joint and several. Substantially all of our consolidated assets are held by the Guarantor Subsidiaries. There are no significant restrictions on the ability of the borrower or any of the Guarantor Subsidiaries to obtain funds through dividends, advances or loans. The obligations under the Credit Facility are secured by a first priority lien on substantially all of our subsidiaries' assets.

9.25% Senior Notes due 2026. On August 10, 2021, our indirect, wholly-owned subsidiary completed an offering of $400 million aggregate principal amount of senior unsecured notes due 2026 (the "9.25% Senior Notes due 2026") that bear interest at 9.25% and were sold at 99.018% of par. Obligations under the 9.25% Senior Notes due 2026 were assumed by ROCC Holdings, LLC (formerly, Penn Virginia Holdings, LLC, hereinafter referred to as "Holdings"), as borrower, and are guaranteed by the subsidiaries of Holdings that guarantee the Credit Facility.

Covenant Compliance. The Credit Facility requires us to maintain (1) a minimum current ratio (as defined in the Credit Facility, which considers the unused portion of the total commitment as a current asset) of 1.00 to 1.00 and (2) a maximum leverage ratio (consolidated indebtedness to EBITDAX, each as defined in the Credit Facility), in each case measured as of the last day of each fiscal quarter of 3.50 to 1.00.

The Credit Facility and the indenture governing the 9.25% Senior Notes due 2026 contain customary affirmative and negative covenants as well as events of default and remedies. If we do not comply with the financial and other covenants in the Credit Facility, the lenders may, subject to customary cure rights, require immediate payment of all amounts outstanding under the Credit Facility.

As of March 31, 2023, we were in compliance with all of the debt covenants.

See Note 7 to the condensed consolidated financial statements included in Part I, Item 1, "Financial Statements" for additional information on our debt.

Critical Accounting Estimates

The process of preparing financial statements in accordance with GAAP requires our management to make estimates and judgments regarding certain items and transactions. It is possible that materially different amounts could be recorded if these estimates and judgments change or if the actual results differ from these estimates and judgments. Disclosure of our most critical accounting estimates that involve the judgment of our management can be found in our Annual Report on Form 10-K for the year ended December 31, 2022.

As described in this Quarterly Report on Form 10-Q as well as the Critical Accounting Estimates disclosures in the Annual Report on Form 10-K, we apply the full cost method to account for our oil and gas properties. At the end of each quarterly reporting period, we perform a Ceiling Test in order to determine if our oil and gas properties have been impaired. For purposes of the Ceiling Test, estimated discounted future net revenues are determined using the prior 12-month's average price based on closing prices on the first day of each month, adjusted for differentials, discounted at 10%. The calculation of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are significant uncertainties inherent in estimating quantities of proved reserves and projecting future rates of production, timing and plan of development. We had no impairments of our proved oil and gas properties during 2023 or 2022.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are interest rate risk and commodity price risk.

Interest Rate Risk

As of March 31, 2023, we had variable-rate borrowings of $240.0 million under the Credit Facility and fixed-rate borrowings of $400.0 million for the 9.25% Senior Notes due 2026 at interest rates of 7.67% and 9.25%, respectively. Assuming a constant borrowing level under the Credit Facility, an increase (decrease) in the interest rate of one percent would result in an increase (decrease) in aggregate interest expense of approximately $2.4 million on an annual basis.

Commodity Price Risk

We produce and sell crude oil, NGLs and natural gas. As a result, our financial results are affected when prices for these commodities fluctuate. Our price risk management programs permit the utilization of derivative financial instruments (such as collars and swaps) to seek to mitigate the price risks associated with fluctuations in commodity prices as they relate to a portion of our anticipated production. The derivative instruments are placed with major financial institutions that we believe are of acceptable credit risk. The fair values of our derivative instruments are significantly affected by fluctuations in the prices of crude oil, NGLs and natural gas.

As of March 31, 2023, our commodity derivative portfolio was in a net liability position in the amount of $9.6 million. The contracts associated with this position are with seven counterparties, all of which are investment grade financial institutions. This concentration may impact our overall credit risk, either positively or negatively, in that these counterparties may be similarly affected by changes in economic or other conditions. We have neither paid to, nor received from, our counterparties any cash collateral in connection with our derivative positions. Furthermore, our derivative contracts are not subject to margin calls or similar accelerations. No significant uncertainties exist related to the collectability of amounts that may be owed to us by these counterparties.

During the three months ended March 31, 2023, we reported net commodity derivative gains of $25.7 million. We have experienced and could continue to experience significant changes in the estimate of derivative gains or losses recognized due to fluctuations in the value of our derivative instruments. Our results of operations are affected by the volatility of unrealized gains and losses and changes in fair value, which fluctuate with changes in crude oil, NGL and natural gas prices. These fluctuations could be significant in a volatile pricing environment. See Note 5 to the condensed consolidated financial statements included in Part I, Item 1, “Financial Statements” for a further description of our commodity price risk management activities.

The following table illustrates the estimated impact on the fair values of our derivative financial instruments and operating income attributable to hypothetical changes in the underlying crude oil prices. This illustration assumes that crude oil production volumes, NGL prices and production volumes, and natural gas prices and production volumes remain constant at anticipated levels. The estimated changes in operating income exclude potential cash receipts or payments in settling these derivative positions.

	Change of 10% per bbl of Crude Oil ($ in millions)	
	Increase	**Decrease**
Effect on the fair value of crude oil derivatives [1]	$ (26.8)	$ 28.2
Effect of crude oil price changes for the remainder of 2023 on operating income, excluding derivatives [2]	$ 60.9	$ (40.6)

[1] Based on derivatives outstanding as of March 31, 2023.

[2] These sensitivities are subject to significant change.

Item 4. Controls and Procedures

(a) Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, performed an evaluation of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act) as of March 31, 2023. Our disclosure controls and procedures are designed to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported on a timely basis and that such information is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that, as of March 31, 2023, such disclosure controls and procedures were effective.

(b) Changes in Internal Control Over Financial Reporting

During the quarter ended March 31, 2023, there were no changes to our internal control over financial reporting 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

We are not aware of any material pending legal or governmental proceedings against us, any material proceedings by governmental officials against us that are pending or contemplated to be brought against us and no such proceedings have been terminated during the period covered by this Quarterly Report on Form 10-Q. See Note 11 to our condensed consolidated financial statements included in Part I, Item 1, "Financial Statements" for additional information regarding our legal and regulatory matters.

Item 1A. Risk Factors

There have been no material changes to the risk factors disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2022.

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

The following table summarizes our repurchase of equity securities during the three months ended March 31, 2023:

Period	Total Number of Shares Repurchased	Average Price Paid Per Unit [1]	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares Yet to be Purchased Under the Publicly Announced Plans or Programs [2]
January 1, 2023 - January 31, 2023	102,959	$ 39.12	102,959	$ 60,813,450
February 1, 2023 - February 28, 2023	18,898	$ 41.70	18,898	$ 60,025,360
March 1, 2023 - March 31, 2023	—	$ —	—	$ 60,025,360
Total	121,857	$ 39.52	121,857	$ 60,025,360

1 The average price paid per share includes any commissions paid to repurchase stock (but excludes any excise taxes).

2 On April 13, 2022, our Board of Directors approved a share repurchase program, under which the Company was authorized to repurchase up to $100 million of its outstanding Class A Common Stock through March 31, 2023. On July 7, 2022, the Board of Directors authorized an increase in the share repurchase program from $100 million to $140 million and extended the term of the program through June 30, 2023. The shares may be repurchased from time to time in open market transactions, through privately negotiated transactions, or by other means in accordance with federal securities laws. The timing, as well as the number and value of shares repurchased under the program, will be determined by the Company at its discretion and will depend on a variety of factors, including among other things, our earnings, liquidity, capital requirements, financial condition, management's assessment of the intrinsic value of the Class A Common Stock, the market price of the Company's Class A Common Stock, general market and economic conditions, available liquidity, compliance with the Company's debt and other agreements, applicable legal requirements and other factors deemed relevant and may be discontinued at any time. We do not intend to repurchase additional shares pending closing of the Baytex Merger.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

(2.1)	Agreement and Plan of Merger, dated as of February 27, 2023, by and between Baytex Energy Corp. and Ranger Oil Corporation (incorporated by reference to Exhibit 2.1 to the Registrant's Current Report on Form 8-K filed on February 28, 2023).
(31.1) *	Certification Pursuant to Rule 13a-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(31.2) *	Certification Pursuant to Rule 13a-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(32.1) **	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(32.2) **	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(101.INS) *	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.
(101.SCH) *	Inline XBRL Taxonomy Extension Schema Document
(101.CAL) *	Inline XBRL Taxonomy Extension Calculation Linkbase Document
(101.DEF) *	Inline XBRL Taxonomy Extension Definition Linkbase Document
(101.LAB) *	Inline XBRL Taxonomy Extension Label Linkbase Document
(101.PRE) *	Inline XBRL Taxonomy Extension Presentation Linkbase Document
(104) *	The cover page of Ranger Oil Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2023, formatted in Inline XBRL (included within the Exhibit 101 attachments).

* Filed herewith.

** Furnished herewith.

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.

RANGER OIL CORPORATION

May 9, 2023	By:	/s/ RUSSELL T KELLEY, JR.
		Russell T Kelley, Jr.
		Senior Vice President, Chief Financial Officer and Treasurer
		(Principal Financial Officer)
May 9, 2023	By:	/s/ KAYLA D. BAIRD
		Kayla D. Baird
		Vice President, Chief Accounting Officer and Controller
		(Principal Accounting Officer)

Exhibit 31.1

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Darrin J. Henke, President and Chief Executive Officer of Ranger Oil Corporation (the “Registrant”), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this “Report”);

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 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 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: May 9, 2023

/s/ DARRIN J. HENKE

Darrin J. Henke
President and Chief Executive Officer

Exhibit 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Russell T Kelley, Jr., Senior Vice President, Chief Financial Officer and Treasurer of Ranger Oil Corporation (the "Registrant"), certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of the Registrant (this "Report");

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 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 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: May 9, 2023

/s/ RUSSELL T KELLEY, JR.

Russell T Kelley, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

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 Ranger Oil Corporation (the “Company”) on Form 10-Q for the quarter ended March 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Darrin J. Henke, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, 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: May 9, 2023

/s/ DARRIN J. HENKE

Darrin J. Henke
President and Chief Executive Officer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company 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 Ranger Oil Corporation (the “Company”) on Form 10-Q for the quarter ended March 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Russell T Kelley, Jr., Senior Vice President, Chief Financial Officer and Treasurer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, 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: May 9, 2023

/s/ RUSSELL T KELLEY, JR.

Russell T Kelley, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

This written statement is being furnished to the Securities and Exchange Commission as an exhibit to the Report. A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.