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 June 30, 2023

OR

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

For the transition period _______________ to _______________

Commission File Number: 001-37362

Black Stone Minerals, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**47-1846692**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1001 Fannin Street, Suite 2020 **Houston, Texas**	**77002**
(Address of principal executive offices)	(Zip code)

(713) 445-3200

(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
Common Units Representing Limited Partner Interests	BSM	New York Stock Exchange

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 and post 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 Act). Yes ☐ No ☒

As of July 28, 2023, there were 209,979,196 common units and 14,711,219 Series B cumulative convertible preferred units of the registrant outstanding.

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)
(In thousands)

	June 30, 2023	December 31, 2022
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 46,666	$ 4,307
Accounts receivable	72,364	135,697
Commodity derivative assets	50,288	31,472
Prepaid expenses and other current assets	2,621	1,905
TOTAL CURRENT ASSETS	171,939	173,381
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $897,836 and $909,344 at June 30, 2023 and December 31, 2022, respectively	3,006,323	3,003,907
Accumulated depreciation, depletion, amortization, and impairment	(1,938,140)	(1,916,919)
Oil and natural gas properties, net	1,068,183	1,086,988
Other property and equipment, net of accumulated depreciation of $13,807 and $13,461 at June 30, 2023 and December 31, 2022, respectively	1,034	1,259
NET PROPERTY AND EQUIPMENT	1,069,217	1,088,247
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	9,197	9,454
TOTAL ASSETS	$ 1,250,353	$ 1,271,082
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 5,601	$ 6,773
Accrued liabilities	10,023	19,729
Commodity derivative liabilities	—	3,243
Other current liabilities	1,136	989
TOTAL CURRENT LIABILITIES	16,760	30,734
LONG–TERM LIABILITIES		
Credit facility	—	10,000
Accrued incentive compensation	1,086	1,884
Commodity derivative liabilities	469	16
Asset retirement obligations	15,283	15,030
Other long-term liabilities	3,514	3,606
TOTAL LIABILITIES	37,112	61,270
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity – Series B cumulative convertible preferred units, 14,711 units outstanding at June 30, 2023 and December 31, 2022, respectively	298,361	298,361
EQUITY		
Partners' equity – general partner interest	—	—
Partners' equity – common units, 209,968 and 209,407 units outstanding at June 30, 2023 and December 31, 2022, respectively	914,880	911,451
TOTAL EQUITY	914,880	911,451
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,250,353	$ 1,271,082

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands, except per unit amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
REVENUE				
Oil and condensate sales	$ 61,551	$ 94,296	$ 122,460	$ 170,127
Natural gas and natural gas liquids sales	41,619	111,181	99,042	186,935
Lease bonus and other income	2,527	2,244	6,502	7,103
Revenue from contracts with customers	105,697	207,721	228,004	364,165
Gain (loss) on commodity derivative instruments	11,303	(27,349)	63,574	(147,369)
TOTAL REVENUE	117,000	180,372	291,578	216,796
OPERATING (INCOME) EXPENSE				
Lease operating expense	2,866	3,199	5,534	6,360
Production costs and ad valorem taxes	12,844	19,504	25,511	33,453
Exploration expense	4	2	8	182
Depreciation, depletion, and amortization	10,421	11,893	21,568	22,810
General and administrative	11,854	12,519	24,502	26,282
Accretion of asset retirement obligations	250	205	495	407
(Gain) loss on sale of assets, net	—	(17)	—	(17)
TOTAL OPERATING EXPENSE	38,239	47,305	77,618	89,477
INCOME (LOSS) FROM OPERATIONS	78,761	133,067	213,960	127,319
OTHER INCOME (EXPENSE)				
Interest and investment income	373	2	530	2
Interest expense	(645)	(1,362)	(1,459)	(2,571)
Other income (expense)	(97)	81	(196)	36
TOTAL OTHER EXPENSE	(369)	(1,279)	(1,125)	(2,533)
NET INCOME (LOSS)	78,392	131,788	212,835	124,786
Distributions on Series B cumulative convertible preferred units	(5,250)	(5,250)	(10,500)	(10,500)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 73,142	$ 126,538	$ 202,335	$ 114,286
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	73,142	126,538	202,335	114,286
	$ 73,142	$ 126,538	$ 202,335	$ 114,286
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:				
Per common unit (basic)	$ 0.35	$ 0.60	$ 0.96	$ 0.55
Per common unit (diluted)	$ 0.35	$ 0.59	$ 0.95	$ 0.55
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:				
Weighted average common units outstanding (basic)	209,967	209,397	209,954	209,360
Weighted average common units outstanding (diluted)	209,967	224,366	224,923	209,360

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)
(In thousands)

	Common units		Partners' equity
BALANCE AT DECEMBER 31, 2022	209,407	$	911,451
Repurchases of common units	(358)		(5,496)
Restricted units granted, net of forfeitures	914		—
Equity–based compensation	—		5,052
Distributions	—		(99,600)
Charges to partners' equity for accrued distribution equivalent rights	—		(733)
Distributions on Series B cumulative convertible preferred units	—		(5,250)
Net income (loss)	—		134,443
BALANCE AT MARCH 31, 2023	209,963	$	939,867
Restricted units granted, net of forfeitures	5		—
Equity–based compensation	—		2,076
Distributions	—		(99,734)
Charges to partners' equity for accrued distribution equivalent rights	—		(471)
Distributions on Series B cumulative convertible preferred units	—		(5,250)
Net income (loss)	—		78,392
BALANCE AT JUNE 30, 2023	209,968		914,880

	Common units		Partners' equity
BALANCE AT DECEMBER 31, 2021	208,666	$	765,268
Repurchases of common units	(262)		(2,991)
Restricted units granted, net of forfeitures	988		—
Equity–based compensation	—		6,659
Distributions	—		(56,462)
Charges to partners' equity for accrued distribution equivalent rights	—		(434)
Distributions on Series B cumulative convertible preferred units	—		(5,250)
Net income (loss)	—		(7,002)
BALANCE AT MARCH 31, 2022	209,392	$	699,788
Restricted units granted, net of forfeitures	7		—
Equity–based compensation	—		2,273
Distributions	—		(83,759)
Charges to partners' equity for accrued distribution equivalent rights	—		(513)
Distributions on Series B cumulative convertible preferred units	—		(5,250)
Net income (loss)	—		131,788
BALANCE AT JUNE 30, 2022	209,399	$	744,327

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

BLACK STONE MINERALS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(In thousands)

	Six Months Ended June 30,	
	2023	**2022**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 212,835	$ 124,786
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	21,568	22,810
Accretion of asset retirement obligations	495	407
Amortization of deferred charges	513	694
(Gain) loss on commodity derivative instruments	(63,574)	147,369
Net cash (paid) received on settlement of commodity derivative instruments	41,469	(93,696)
Equity-based compensation	4,635	7,275
(Gain) loss on sale of assets, net	—	(17)
Changes in operating assets and liabilities:		
Accounts receivable	63,477	(43,192)
Prepaid expenses and other current assets	(715)	(501)
Accounts payable, accrued liabilities, and other	(10,083)	(5,359)
Settlement of asset retirement obligations	(195)	(437)
NET CASH PROVIDED BY OPERATING ACTIVITIES	270,425	160,139
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to oil and natural gas properties	(2,503)	(10,072)
Additions to oil and natural gas properties leasehold costs	(9)	—
Purchases of other property and equipment	(121)	(41)
Proceeds from the sale of oil and natural gas properties	—	17
Proceeds from farmouts of oil and natural gas properties	—	9,951
NET CASH USED IN INVESTING ACTIVITIES	(2,633)	(145)
CASH FLOWS FROM FINANCING ACTIVITIES		
Distributions to common unitholders	(199,334)	(140,221)
Distributions to Series B cumulative convertible preferred unitholders	(10,500)	(10,500)
Repurchases of common units	(5,496)	(2,991)
Borrowings under credit facility	64,000	153,000
Repayments under credit facility	(74,000)	(156,000)
Debt issuance costs and other	(103)	—
NET CASH USED IN FINANCING ACTIVITIES	(225,433)	(156,712)
NET CHANGE IN CASH AND CASH EQUIVALENTS	42,359	3,282
CASH AND CASH EQUIVALENTS – beginning of the period	4,307	8,876
CASH AND CASH EQUIVALENTS – end of the period	$ 46,666	$ 12,158
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 975	$ 1,864

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

NOTE 1 - BUSINESS AND BASIS OF PRESENTATION

Description of the Business

Black Stone Minerals, L.P. (“BSM” or the “Partnership”) is a publicly traded Delaware limited partnership that owns oil and natural gas mineral interests, which make up the vast majority of the asset base. The Partnership's assets also include nonparticipating royalty interests and overriding royalty interests. These interests, which are substantially non-cost-bearing, are collectively referred to as “mineral and royalty interests.” The Partnership’s mineral and royalty interests are located in 41 states in the continental United States ("U.S."), including all of the major onshore producing basins. The Partnership also owns non-operated working interests in certain oil and natural gas properties. The Partnership's common units trade on the New York Stock Exchange under the symbol "BSM."

Basis of Presentation

The accompanying unaudited interim consolidated financial statements of the Partnership have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission (“SEC”). These unaudited interim consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Partnership’s consolidated financial statements included in the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2022 ("2022 Annual Report on Form 10-K").

The unaudited interim consolidated financial statements include the consolidated results of the Partnership. The results of operations for the six months ended June 30, 2023 are not necessarily indicative of the results to be expected for the full year.

In the opinion of management, all adjustments, which are of a normal and recurring nature, necessary for the fair presentation of the financial results for all periods presented have been reflected. All intercompany balances and transactions have been eliminated.

The Partnership evaluates the significant terms of its investments to determine the method of accounting to be applied to each respective investment. Investments in which the Partnership has less than a 20% ownership interest and does not have control or exercise significant influence are accounted for using fair value or cost minus impairment if fair value is not readily determinable. Investments in which the Partnership exercises control are consolidated, and the noncontrolling interests of such investments, which are not attributable directly or indirectly to the Partnership, are presented as a separate component of net income (loss) and equity.

The unaudited interim consolidated financial statements include undivided interests in oil and natural gas property rights. The Partnership accounts for its share of oil and natural gas property rights by reporting its proportionate share of assets, liabilities, revenues, costs, and cash flows within the relevant lines on the accompanying unaudited interim consolidated balance sheets, statements of operations, and statements of cash flows.

Segment Reporting

The Partnership operates in a single operating and reportable segment. Operating segments are defined as components of an enterprise for which separate financial information is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and assess performance. The Partnership’s chief executive officer has been determined to be the chief operating decision maker and allocates resources and assesses performance based upon financial information at the consolidated level.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Significant accounting policies are disclosed in the Partnership’s 2022 Annual Report on Form 10-K. There have been no changes in such policies or the application of such policies during the six months ended June 30, 2023.

Accounts Receivable

The following table presents information about the Partnership's accounts receivable:

	June 30, 2023		December 31, 2022	
	(in thousands)			
Accounts receivable:				
Revenues from contracts with customers	$	65,371	$	129,078
Other		6,993		6,619
Total accounts receivable	$	72,364	$	135,697

NOTE 3 - OIL AND NATURAL GAS PROPERTIES

Acquisitions and divestitures

The Partnership had no material acquisition or divestiture activity during 2022 or the six months ended June 30, 2023.

Farmout Agreements

The Partnership has entered into farmout arrangements designed to reduce its working interest capital expenditures and thereby significantly lowering its capital spending other than for mineral and royalty interest acquisitions. Under these agreements, the Partnership conveyed its rights to participate in certain non-operated working interest opportunities to external capital providers while retaining value from these interests in the form of additional royalty income or retained economic interests.

In 2017, the Partnership entered into farmout arrangements with Canaan Resource Partners ("Canaan") and Pivotal Petroleum Partners ("Pivotal") in the Shelby Trough area of East Texas where the Partnership owns a concentrated, relatively high-interest royalty position. This area was under active development by XTO Energy Inc. ("XTO") in San Augustine County, Texas and BPX Energy in Angelina County, Texas through 2019. These farmout agreements were superseded and replaced by the new farmout agreements discussed below.

San Augustine Farmout

In May 2021, BSM and Aethon Energy ("Aethon") entered into an agreement to develop certain of the Partnership's undeveloped acreage in San Augustine County. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to BSM's mineral and leasehold acreage in the contract area. The agreement calls for a minimum of five wells to be drilled in the initial program year, which began in the third quarter of 2021, 10 wells to be drilled in the second and third program years, and, thereafter, a minimum of 12 wells per year beginning with the fourth program year. The Partnership's development agreement with Aethon and related drilling commitments covering its San Augustine County acreage is independent of the development agreement and associated commitments covering Angelina County discussed below.

In May 2021, the Partnership entered into a new farmout agreement (the "Canaan Farmout") with Canaan and in December 2021, the Partnership entered into a farmout agreement (the "Azul Farmout") with Azul-SA, LLC ("Azul"). In April 2022, the Partnership amended the Canaan Farmout and entered into a farmout agreement (the "JWM Farmout") with JWM Oil & Gas LLC ("JWM"). These agreements cover all of the Partnership's share of working interests under active development by Aethon in San Augustine County, Texas and continue for a 10 year period, unless earlier terminated in accordance with the terms of the agreements. Canaan, Azul, and JWM will each earn a percentage of the Partnership's working interest in wells drilled and operated by Aethon within the contract area subject to the agreements. Canaan, Azul, and JWM are obligated to fund the development of wells drilled by Aethon in the initial program year, and thereafter, have certain rights and options to continue funding the Partnership's working interest for the duration of each farmout agreement. The Partnership will receive an overriding royalty interest ("ORRI") before payout and an increased ORRI after payout on all wells drilled under the farmout agreements. As of June 30, 2023, 15 wells have been spud by Aethon in the contract area subject to the Canaan, Azul, and JWM Farmouts.

The following tables present the working interests each farmout partner will earn within the contract area under the San Augustine farmout agreements:

Brent Miller Area

Farmout Partner	% of Partnership's Working Interest	Maximum % on an 8/8ths basis
Canaan	64.0 %	32.0 %
Azul	20.0 %	10.0 %
JWM	16.0 %	8.0 %
Total	100.0 %	50.0 %

Other Areas

Farmout Partner	% of Partnership's Working Interest	Maximum % on an 8/8ths basis
Canaan	40.0 %	10.0 %
Azul	50.0 %	12.5 %
JWM	10.0 %	2.5 %
Total	100.0 %	25.0 %

Angelina Farmout

In May 2020, the Partnership entered into a development agreement with Aethon to develop certain portions of the area forfeited by BPX Energy in Angelina County, Texas. The agreement provides for minimum well commitments by Aethon in exchange for reduced royalty rates and exclusive access to the Partnership's mineral and leasehold acreage in the contract area. The agreement calls for a minimum of four wells to be drilled in the initial program year, which began in the third quarter of 2020, 10 wells to be drilled in the second program year, and, beginning with the third program year, 15 wells per year beginning thereafter.

In November 2020, the Partnership entered into a new farmout agreement (the "Pivotal Farmout") with Pivotal. The Pivotal Farmout covers the Partnership's share of working interest under active development by Aethon in Angelina County, Texas and continues until April 2028, unless earlier terminated in accordance to the terms of the agreement. Pivotal will earn 100% of the Partnership's working interest (ranging from approximately 12.5% to 25% on an 8/8ths basis) in wells drilled and operated by Aethon within the contract area subject to the agreement. Pivotal is obligated to fund the development of all wells drilled by Aethon in the initial program year and thereafter, Pivotal has certain rights and options to continue funding the Partnership's working interests for the duration of the Pivotal Farmout. Once Pivotal achieves a specified payout for a designated well group, the Partnership will obtain a majority of the original working interest in such well group. As of June 30, 2023, 34 wells have been spud by Aethon in the contract area subject to the Pivotal Farmout.

Impairment of Oil and Natural Gas Properties

Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. When assessing producing properties for impairment, the Partnership compares the expected undiscounted projected future cash flows of the producing properties to the carrying amount of the producing properties to determine recoverability. When the carrying amount exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties.

The Partnership did not recognize any impairment of oil and natural gas properties for the three and six months ended June 30, 2023 and 2022, respectively. See Note 5 - Fair Value Measurements for further discussion.

NOTE 4 - COMMODITY DERIVATIVE FINANCIAL INSTRUMENTS

The Partnership’s ongoing operations expose it to changes in the market price for oil and natural gas. To mitigate the inherent commodity price risk associated with its operations, the Partnership uses oil and natural gas commodity derivative financial instruments. From time to time, such instruments may include variable-to-fixed-price swaps, costless collars, fixed-price contracts and other contractual arrangements. A fixed-price swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. A costless collar contract between the Partnership and the counterparty specifies a floor and a ceiling commodity price and a future settlement date. The Partnership enters into oil and natural gas derivative contracts that contain netting arrangements with each counterparty. The Partnership does not enter into derivative instruments for speculative purposes.

As of June 30, 2023, the Partnership’s open derivative contracts consisted of fixed-price swap contracts. The Partnership has not designated any of its contracts as fair value or cash flow hedges. Accordingly, the changes in the fair value of the contracts are included in the consolidated statement of operations in the period of the change. All derivative gains and losses from the Partnership’s derivative contracts have been recognized in revenue in the Partnership's accompanying consolidated statements of operations. Derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership’s accompanying consolidated balance sheets as of June 30, 2023 and December 31, 2022. See Note 5 - Fair Value Measurements for further discussion.

The Partnership's derivative contracts expose it to credit risk in the event of nonperformance by counterparties that may adversely impact the fair value of the Partnership's commodity derivative assets. While the Partnership does not require its derivative contract counterparties to post collateral, the Partnership does evaluate the credit standing of such counterparties as deemed appropriate. This evaluation includes reviewing a counterparty’s credit rating and latest financial information. As of June 30, 2023, the Partnership had seven counterparties, all of which are rated Baa1 or better by Moody’s and are lenders under the Credit Facility.

The tables below summarize the fair values and classifications of the Partnership's derivative instruments, as well as the gross recognized derivative assets, liabilities, and amounts offset in the consolidated balance sheets as of each date:

		June 30, 2023		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 51,104	$ (816)	$ 50,288
Long-term asset	Deferred charges and other long-term assets	1,894	(667)	1,227
Total assets		$ 52,998	$ (1,483)	$ 51,515
Liabilities:				
Current liability	Commodity derivative liabilities	$ 816	$ (816)	$ —
Long-term liability	Commodity derivative liabilities	1,136	(667)	469
Total liabilities		$ 1,952	$ (1,483)	$ 469

		December 31, 2022		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(in thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 41,648	$ (10,176)	$ 31,472
Long-term asset	Deferred charges and other long-term assets	797	(69)	728
Total assets		$ 42,445	$ (10,245)	$ 32,200
Liabilities:				
Current liability	Commodity derivative liabilities	$ 13,419	$ (10,176)	$ 3,243
Long-term liability	Commodity derivative liabilities	85	(69)	16
Total liabilities		$ 13,504	$ (10,245)	$ 3,259

Changes in the fair values of the Partnership's derivative instruments (both assets and liabilities) are presented on a net basis in the accompanying consolidated statements of operations and consolidated statements of cash flows and consist of the following for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives not designated as hedging instruments	**2023**	**2022**	**2023**	**2022**
	(in thousands)			
Beginning fair value of commodity derivative instruments	$ 67,927	$ (142,321)	$ 28,941	$ (53,545)
Gain (loss) on oil derivative instruments	7,360	(16,275)	14,782	(65,117)
Gain (loss) on natural gas derivative instruments	3,943	(11,074)	48,792	(82,252)
Net cash paid (received) on settlements of oil derivative instruments	(3,172)	26,345	(1,772)	42,237
Net cash paid (received) on settlements of natural gas derivative instruments	(25,012)	36,107	(39,697)	51,459
Net change in fair value of commodity derivative instruments	(16,881)	35,103	22,105	(53,673)
Ending fair value of commodity derivative instruments	$ 51,046	$ (107,218)	$ 51,046	$ (107,218)

The Partnership had the following open derivative contracts for oil as of June 30, 2023:

			Range (Per Bbl)	
Period and Type of Contract	**Volume (Bbl)**	**Weighted Average Price (Per Bbl)**	**Low**	**High**
Oil Swap Contracts:				
2023				
Second Quarter	180,000	$ 80.80	$ 73.00	$ 89.50
Third Quarter	540,000	80.80	73.00	89.50
Fourth Quarter	540,000	80.80	73.00	89.50
2024				
First Quarter	450,000	$ 68.98	$ 67.00	$ 72.82
Second Quarter	450,000	68.98	67.00	72.82
Third Quarter	450,000	68.98	67.00	72.82
Fourth Quarter	450,000	68.98	67.00	72.82

The Partnership had the following open derivative contracts for natural gas as of June 30, 2023:

			Range (Per MMBtu)	
Period and Type of Contract	**Volume (MMBtu)**	**Weighted Average Price (Per MMBtu)**	**Low**	**High**
Natural Gas Swap Contracts:				
2023				
Third Quarter	8,280,000	$ 5.15	$ 3.28	$ 6.59
Fourth Quarter	8,280,000	5.15	3.28	6.59
2024				
First Quarter	10,010,000	$ 3.57	$ 3.48	$ 3.76
Second Quarter	10,010,000	3.57	3.48	3.76
Third Quarter	10,120,000	3.57	3.48	3.76
Fourth Quarter	10,120,000	3.57	3.48	3.76

NOTE 5 - FAIR VALUE MEASUREMENTS

Fair value is defined as the amount at which an asset (or liability) could be bought (or incurred) or sold (or settled) in an orderly transaction between market participants at the measurement date. Further, ASC 820, *Fair Value Measurement*, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value, and includes certain disclosure requirements. Fair value estimates are based on either (i) actual market data or (ii) assumptions that other market participants would use in pricing an asset or liability, including estimates of risk.

ASC 820 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

Level 1—Unadjusted quoted prices for identical assets or liabilities in active markets.

Level 2—Quoted prices for similar assets or liabilities in non-active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3—Inputs that are unobservable and significant to the fair value measurement (including the Partnership’s own assumptions in determining fair value).

A financial instrument’s categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Partnership’s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability.

The carrying value of the Partnership's cash and cash equivalents, receivables, and payables approximate fair value due to the short-term nature of the instruments. The estimated carrying value of all debt as of June 30, 2023 and December 31, 2022 approximated the fair value due to variable market rates of interest. These debt fair values, which are Level 3 measurements, were estimated based on the Partnership’s incremental borrowing rates for similar types of borrowing arrangements, when quoted market prices were not available. The estimated fair values of the Partnership’s financial instruments are not necessarily indicative of the amounts that would be realized in a current market exchange.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership estimated the fair value of commodity derivative financial instruments using the market approach via a model that uses inputs that are observable in the market or can be derived from, or corroborated by, observable data. See Note 4 - Commodity Derivative Financial Instruments for further discussion.

The following table presents information about the Partnership’s assets and liabilities measured at fair value on a recurring basis:

	Fair Value Measurements Using			Effect of Counterparty Netting	Total
	Level 1	Level 2	Level 3		
	(in thousands)				
As of June 30, 2023					
Financial Assets					
Commodity derivative instruments	$ —	$ 52,998	$ —	$ (1,483)	$ 51,515
Financial Liabilities					
Commodity derivative instruments	$ —	$ 1,952	$ —	$ (1,483)	$ 469
As of December 31, 2022					
Financial Assets					
Commodity derivative instruments	$ —	$ 42,445	$ —	$ (10,245)	$ 32,200
Financial Liabilities					
Commodity derivative instruments	$ —	$ 13,504	$ —	$ (10,245)	$ 3,259

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Nonfinancial assets and liabilities measured at fair value on a non-recurring basis include certain nonfinancial assets and liabilities as may be acquired in a business combination and measurements of oil and natural gas property values for assessment of impairment.

The determination of the fair values of proved and unproved properties acquired in business combinations are estimated by discounting projected future cash flows. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, timing of future production, and a risk-adjusted discount rate. The Partnership has designated these measurements as Level 3. The Partnership had no business combinations for the six months ended June 30, 2023 or the year ended December 31, 2022. See Note 3 - Oil and Natural Gas Properties.

Oil and natural gas properties are measured at fair value on a non-recurring basis using the income approach when assessing for impairment. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and a risk-adjusted discount rate.

The Partnership’s estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty, particularly in the current volatile market, and cannot be determined with precision. Changes to these estimates, particularly related to economic reserves, future commodity prices, and timing of future production could result in additional impairment charges in the future. There were no significant changes in valuation techniques or related inputs as of June 30, 2023 or December 31, 2022. There were no assets measured at fair value on a non-recurring basis for the six months ended June 30, 2023 or the year ended December 31, 2022.

NOTE 6 - CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement, as amended (the “Credit Facility”). The Credit Facility has an aggregate maximum credit amount of $1.0 billion. The commitment of the lenders equals the least of the aggregate maximum credit amount, the then-effective borrowing base, and the aggregate elected commitment, as it may be adjusted from time to time. The amount of the borrowing base is redetermined semi-annually, usually in October and April, and is derived from the value of the Partnership’s oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. The Partnership and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. The Partnership also has the right to request a redetermination following the acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition. The borrowing base is also adjusted if we terminate our hedge positions or sell oil and natural gas property interests that have a combined value exceeding 5% of the current borrowing base. In these circumstances, the borrowing base will be adjusted by the value attributed to the terminated hedge positions or the oil and natural gas property interests sold in the most recent borrowing base. The April and October 2021 and April 2022 borrowing base redeterminations reaffirmed the borrowing base at $400.0 million. In October 2022, the Partnership revised and amended the Credit Facility to extend the maturity date from November 1, 2024 to October 31, 2027. Concurrent with the Credit Facility amendment, the borrowing base under the Credit Facility was increased to $550.0 million and the Partnership elected to lower commitments under the Credit Facility from $400.0 million to $375.0 million. The April 2023 borrowing base redetermination reaffirmed the borrowing base at $550.0 million with cash commitments at $375.0 million. The next semi-annual redetermination is scheduled for October 2023.

In October 2022, the Credit Facility was amended to replace the LIBOR rate with the secured overnight financing rate published by the Federal Reserve Bank of New York ("SOFR"). Outstanding borrowings under the Credit Facility bear interest at a floating rate elected by the Partnership equal to a base rate (which is a rate per annum equal to the highest of (a) the Prime Rate in effect on such day, (b) the Federal Funds Rate in effect on such day plus 0.50%, and (c) Adjusted Term SOFR for a one month tenor in effect on such day plus 1.00%) or Adjusted Term SOFR, in each case, plus the applicable margin. As of December 31, 2022 and June 30, 2023, the applicable margin for the alternative base rate ranged from 1.50% to 2.50% and the Adjusted Term SOFR margin ranged from 2.50% to 3.50%, depending on the borrowings outstanding in relation to the borrowing base.

The weighted-average interest rate of the Credit Facility was 7.30% during the quarter ended June 30, 2023 and the weighted-average interest rate was 6.92% as of December 31, 2022. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days, in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.500% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Credit Facility is secured by substantially all of the Partnership’s oil and natural gas production and assets.

The Credit Facility contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Credit Facility requires the Partnership to maintain a current ratio of not less than 1.0:1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5:1.0. Distributions are not permitted if there is a default under the Credit Facility (including the failure to satisfy one of the financial covenants), if the availability under the Credit Facility is less than 10% of the lenders' commitments, or if total debt to EBITDAX is greater than 3.0. As of June 30, 2023, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was zero and $10.0 million at June 30, 2023 and December 31, 2022, respectively. The unused portion of the available borrowings under the Credit Facility were $375.0 million and $365.0 million at June 30, 2023 and December 31, 2022, respectively.

NOTE 7 - COMMITMENTS AND CONTINGENCIES

Environmental Matters

The Partnership’s business includes activities that are subject to U.S. federal, state, and local environmental regulations with regard to air, land, and water quality and other environmental matters.

The Partnership does not consider the potential remediation costs that could result from issues identified in any environmental site assessments to be significant to the consolidated financial statements, and no provision for potential remediation costs has been recorded.

Litigation

From time to time, the Partnership is involved in legal actions and claims arising in the ordinary course of business. The Partnership believes existing claims as of June 30, 2023 will be resolved without material adverse effect on the Partnership’s financial condition or operations.

NOTE 8 - INCENTIVE COMPENSATION

The table below summarizes incentive compensation expense recorded in the General and administrative line item of the consolidated statements of operations for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in thousands)			
Cash—short and long-term incentive plans	$ 854	$ 1,963	$ 1,933	$ 2,959
Equity-based compensation—restricted common units	942	1,049	1,896	1,976
Equity-based compensation—restricted performance units	1,053	1,144	1,686	4,237
Board of Directors incentive plan	522	531	1,053	1,062
Total incentive compensation expense	$ 3,371	$ 4,687	$ 6,568	$ 10,234

For the six months ended June 30, 2023, the Partnership repurchased 357,761 common units at an average price of $15.36 per unit for the purpose of satisfying tax withholding obligations upon the vesting of certain long-term incentive equity awards held by our executive officers and certain other employees. Specifically, when an employee's equity award vests, the Partnership withholds a portion of the shares to cover the employee's tax liability.

In the first quarter of 2022, the board of directors of the Partnership's general partner (the "Board") approved a grant of awards to all employees dependent on the achievement of an aspirational production target to be measured in the fourth quarter of 2025 (the "Aspirational Awards"). The Aspirational Awards include performance cash awards and performance equity awards in the form of restricted performance units. To the extent earned, each performance unit represents the right to receive one common unit. The performance cash awards and performance units are eligible to become earned at the end of the requisite service period on December 31, 2025 if the minimum performance metrics are achieved. The minimum performance metrics are at least 42 Mboe per day of average daily royalty production in either the fourth quarter or the month of December of 2025 while maintaining a net debt to EBITDA ratio less than or equal to 1.0 on December 31, 2025. Average daily royalty production does not include production attributable to acquisitions consummated during the performance period. Compensation expense related to the Aspirational Awards will be recorded over the service period when achievement of the performance condition is probable. Total compensation expense to be recognized over the life of the Aspirational Awards consists of $5.2 million for the performance cash awards and $14.5 million for the performance equity awards (1,221,891 performance units with a weighted-average grant date fair value of $11.83 per unit). As of June 30, 2023, the Partnership determined achievement of the performance condition was not yet probable and no expense was recognized.

NOTE 9 - PREFERRED UNITS

Series B Cumulative Convertible Preferred Units

On November 28, 2017, the Partnership issued and sold in a private placement 14,711,219 Series B cumulative convertible preferred units representing limited partner interests in the Partnership for a cash purchase price of $20.3926 per Series B cumulative convertible preferred unit, resulting in total proceeds of approximately $300.0 million.

The Series B cumulative convertible preferred units are entitled to an annual distribution of 7.0%, payable on a quarterly basis in arrears; provided that the distribution rate will be adjusted as follows: commencing on November 28, 2023 and readjusting every two years thereafter (each, a "Readjustment Date"), the rate will equal the greater of (i) the distribution rate in effect immediately prior to the relevant Readjustment Date and (ii) the 10-year Treasury Rate as of such Readjustment Date plus 5.5% per annum; provided, however, that for any quarter in which quarterly distributions are accrued but unpaid, the then-distribution rate shall be increased by 2.0% per annum for such quarter.

The Series B cumulative convertible preferred units may be converted by each holder at its option, in whole or in part, into common units on a one-for-one basis at the purchase price of $20.3926, adjusted to give effect to any accrued but unpaid accumulated distributions on the applicable Series B cumulative convertible preferred units through the most recent declaration date. However, the Partnership shall not be obligated to honor any request for such conversion if such request does not involve an underlying value of common units of at least $10.0 million based on the closing trading price of common units on the trading day immediately preceding the conversion notice date, or such lesser amount to the extent such exercise covers all of a holder's Series B cumulative convertible preferred units.

The Partnership has the option to redeem all or a portion (equal to or greater than $100 million) of the Series B cumulative convertible preferred units for a 90 day period beginning on November 28, 2023 at a redemption price of $21.41 per Series B cumulative convertible preferred unit, which is equal to 105% of par value. Thereafter, the Partnership may redeem the Series B cumulative convertible preferred units at par within a 90 day period on each second anniversary following November 28, 2023.

The Series B cumulative convertible preferred units had a carrying value of $298.4 million, including accrued distributions of $5.3 million, as of June 30, 2023 and December 31, 2022. The Series B cumulative convertible preferred units are classified as mezzanine equity on the consolidated balance sheets since certain provisions of redemption are outside the control of the Partnership.

NOTE 10 - EARNINGS PER UNIT

The Partnership applies the two-class method for purposes of calculating earnings per unit (“EPU”). The holders of the Partnership’s restricted common units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common units are included in the calculation of basic earnings per unit. For the periods presented, the amount of earnings allocated to these participating units was not material.

Net income (loss) attributable to the Partnership is allocated to the Partnership’s general partner and the common unitholders in proportion to their pro rata ownership after giving effect to distributions, if any, declared during the period.

The Partnership assesses the Series B cumulative convertible preferred units on an as-converted basis for the purpose of calculating diluted EPU. The Partnership’s restricted performance unit awards are contingently issuable units that are considered in the calculation of diluted EPU. The Partnership assesses the number of units that would be issuable, if any, under the terms of the arrangement if the end of the reporting period were the end of the contingency period.

The following table sets forth the computation of basic and diluted earnings per common unit:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in thousands, except per unit amounts)			
NET INCOME (LOSS)	$ 78,392	$ 131,788	$ 212,835	$ 124,786
Distributions on Series B cumulative convertible preferred units	(5,250)	(5,250)	(10,500)	(10,500)
NET INCOME (LOSS) ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 73,142	$ 126,538	$ 202,335	$ 114,286
ALLOCATION OF NET INCOME (LOSS):				
General partner interest	$ —	$ —	$ —	$ —
Common units	73,142	126,538	202,335	114,286
	$ 73,142	$ 126,538	$ 202,335	$ 114,286
NUMERATOR:				
Numerator for basic EPU - Net income (loss) attributable to common unitholders	$ 73,142	$ 126,538	$ 202,335	$ 114,286
Effect of dilutive securities	—	5,250	10,500	—
Numerator for diluted EPU - net income (loss) attributable to common unitholders after the effect of dilutive securities	$ 73,142	$ 131,788	$ 212,835	$ 114,286
DENOMINATOR:				
Denominator for basic EPU - weighted average common units outstanding (basic)	209,967	209,397	209,954	209,360
Effect of dilutive securities	—	14,969	14,969	—
Denominator for diluted EPU - weighted average number of common units outstanding after the effect of dilutive securities	209,967	224,366	224,923	209,360
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:				
Per common unit (basic)	$ 0.35	$ 0.60	$ 0.96	$ 0.55
Per common unit (diluted)	$ 0.35	$ 0.59	$ 0.95	$ 0.55

The following units of potentially dilutive securities were excluded from the computation of diluted weighted average units outstanding because their inclusion would be anti-dilutive:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in thousands)			
Potentially dilutive securities (common units):				
Series B cumulative convertible preferred units on an as-converted basis	14,969	—	—	14,969

NOTE 11 - COMMON UNITS

Common Units

The common units represent limited partner interests in the Partnership. The holders of common units are entitled to participate in distributions and exercise the rights and privileges provided to limited partners holding common units under the partnership agreement.

The partnership agreement restricts unitholders' voting rights by providing that any units held by a person or group that owns 15% or more of any class of units then outstanding, other than the limited partners in Black Stone Minerals Company, L.P. prior to the IPO, their transferees, persons who acquired such units with the prior approval of the Board, holders of Series B cumulative convertible preferred units in connection with any vote, consent or approval of the Series B cumulative convertible preferred units as a separate class, and persons who own 15% or more of any class as a result of any redemption or purchase of any other person's units or similar action by the Partnership or any conversion of the Series B cumulative convertible preferred units at the Partnership's option or in connection with a change of control, may not vote on any matter.

The partnership agreement generally provides that any distributions are paid each quarter in the following manner:

- *first*, to the holders of the Series B cumulative convertible preferred units in an amount equal to 7% per annum, subject to certain adjustments; and
- *second*, to the holders of common units.

The following table provides information about the Partnership's per unit distributions to common unitholders:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	**2022**	**2023**	**2022**
Distributions declared and paid per common unit	$ 0.4750	$ 0.4000	$ 0.9500	$ 0.6700

NOTE 12 - SUBSEQUENT EVENTS

On July 25, 2023, the Board approved a distribution for the three months ended June 30, 2023 of $0.475 per common unit. Distributions will be payable on August 18, 2023 to unitholders of record at the close of business on August 11, 2023.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q, as well as our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2022 ("2022 Annual Report on Form 10-K"). This discussion and analysis contains forward-looking statements that involve risks, uncertainties, and assumptions. Actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors, including those set forth under "Cautionary Note Regarding Forward-Looking Statements" and "Part II, Item 1A. Risk Factors."

Cautionary Note Regarding Forward-Looking Statements

Certain statements and information in this Quarterly Report on Form 10-Q may constitute "forward-looking statements." The words "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "would," "could," or other similar expressions are intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, those summarized below:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- the overall supply and demand for oil and natural gas, regional supply and demand factors, delays, or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- general economic, business, or industry conditions, including slowdowns, domestically and internationally and volatility in the securities, capital or credit markets;
- competition in the oil and natural gas industry;
- the level of drilling activity by our operators particularly in areas such as the Shelby Trough where we have concentrated acreage positions;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services, or personnel;
- restrictions on the use of water for hydraulic fracturing;
- the availability of pipeline capacity and transportation facilities;
- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;

- future cash flows and liquidity, including our ability to generate sufficient cash to pay quarterly distributions;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;
- the ability of our operators to keep pace with technological advancements;
- conservation measures and general concern about the environmental impact of the production and use of fossil fuels;
- cybersecurity incidents, including data security breaches or computer viruses; and
- certain factors discussed elsewhere in this filing.

For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see "Risk Factors" in our 2022 Annual Report on Form 10-K and in this Quarterly Report on Form 10-Q.

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

Overview

We are one of the largest owners and managers of oil and natural gas mineral interests in the United States. Our principal business is maximizing the value of our existing portfolio of mineral and royalty assets through active management and expanding our asset base through acquisitions of additional mineral and royalty interests. We maximize value through marketing our mineral assets for lease, creatively structuring the terms on those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working interest basis. We believe our large, diversified asset base and long-lived, non-cost-bearing mineral and royalty interests provide for stable production and reserves over time, allowing the majority of generated cash flow to be distributed to unitholders.

As of June 30, 2023, our mineral and royalty interests were located in 41 states in the continental United States, including all of the major onshore producing basins. These non-cost-bearing interests include ownership in over 68,000 producing wells. We also own non-operated working interests, a significant portion of which are on our positions where we also have a mineral and royalty interest. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when control of the oil and natural gas produced is transferred to the customer and collectability of the sales price is reasonably assured. Our other sources of revenue include mineral lease bonus and delay rentals, which are recognized as revenue according to the terms of the lease agreements.

Recent Developments

Shelby Trough Development Update

Aethon continues to perform with drilling and completing wells according to our development agreements. Aethon has five rigs currently on our acreage in the Shelby Trough. Aethon has successfully turned 16 wells to sales and has commenced operations on 18 additional wells under the development agreement covering Angelina County. Aethon has successfully turned six wells to sales and has another nine wells awaiting completion operations under the separate development agreement covering San Augustine County. Additionally, XTO Energy has turned four wells to sales in the second quarter and has two wells currently awaiting completion operations.

Austin Chalk Update

We have entered into agreements with multiple operators to drill wells in the areas of the Austin Chalk in East Texas, where we have significant acreage positions. The results of the 2021 three well test program in the Brookeland Field demonstrated that modern completion technology has the potential to greatly improve production rates and increase reserves when compared to the vintage, unstimulated wells in the Austin Chalk formation. Eight operators are actively engaged in redevelopment of the field. We have also reached an agreement with one of these operators to drill 10 wells in the field over the next two years. To date, 26 wells with modern completions are now producing in the field, and an additional three wells are currently either being drilled or completed.

Business Environment

The information below is designed to give a broad overview of the oil and natural gas business environment as it affects us.

Commodity Prices and Demand

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. To manage the variability in cash flows associated with the projected sale of our oil and natural gas production, we use various derivative instruments, which have recently consisted of fixed-price swap contracts.

Commodity prices during the six months ended June 30, 2023 decreased from the corresponding prior period, due to several factors, including reduced demand for natural gas and rising global oil inventories. Natural gas prices decreased in the first quarter of 2023 and remained flat in the second quarter as a result of increases in dry natural gas production, lower-than-average consumption due to mild winter weather conditions in the first two months of the year, and the resulting higher-than-average storage inventories. The current price environment remains uncertain as responses to elevated inflation and the conflict in Ukraine continue to evolve. The EIA expects relatively flat U.S. natural gas production and year-over-year growth in consumption in the electric power sector to raise prices in the second half of 2023. Given the dynamic nature of these events, we cannot reasonably estimate the period of time that these market conditions will persist. While we use derivative instruments to partially mitigate the impact of commodity price volatility, our revenues and operating results depend significantly upon the prevailing prices for oil and natural gas.

The following table reflects commodity prices at the end of each quarter presented:

	2023		2022	
Benchmark Prices[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
WTI spot oil price ($/Bbl)	$ 70.66	$ 75.68	$ 107.76	$ 100.53
Henry Hub spot natural gas ($/MMBtu)	2.48	2.10	6.54	5.46

[1] Source: EIA

Rig Count

As we are not the operator of record on any producing properties, drilling on our acreage is dependent upon the exploration and production companies that lease our acreage. In addition to drilling plans that we seek from our operators, we also monitor rig counts in an effort to identify existing and future leasing and drilling activity on our acreage.

The following table shows the rig count at the end of each quarter presented:

	2023		2022	
U.S. Rotary Rig Count[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
Oil	545	592	594	531
Natural gas	124	160	157	137
Other	5	3	2	2
Total	674	755	753	670

[1] Source: Baker Hughes Incorporated

Natural Gas Storage

A substantial portion of our revenue is derived from sales of oil production attributable to our interests; however, the majority of our production is natural gas. Natural gas prices are significantly influenced by storage levels throughout the year. Accordingly, we monitor the natural gas storage reports regularly in the evaluation of our business and its outlook.

Historically, natural gas supply and demand fluctuates on a seasonal basis. From April to October, when the weather is warmer and natural gas demand is lower, natural gas storage levels generally increase. From November to March, storage levels typically decline as utility companies draw natural gas from storage to meet increased heating demand due to colder weather. In order to maintain sufficient storage levels for increased seasonal demand, a portion of natural gas production during the summer months must be used for storage injection. The portion of production used for storage varies from year to year depending on the demand from the previous winter and the demand for electricity used for cooling during the summer months. The EIA estimates that natural gas inventories will conclude the injection season in October 2023 at 3.9 Tcf, which is 7% higher than the previous five-year average.

The following table shows natural gas storage volumes by region at the end of each quarter presented:

	2023		2022	
Region[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
East	643	335	461	268
Midwest	705	421	535	317
Mountain	173	80	134	89
Pacific	216	73	235	161
South Central	1,141	921	886	581
Total	2,878	1,830	2,251	1,416

[1] Source: EIA

Natural Gas Exports

The EIA expects an increase in U.S. LNG exports resulting from two major LNG export projects under construction that will come online by the end of 2024. Net natural gas exports averaged 12.1 Bcf per day in the second quarter of 2023, a 14% increase from the 2022 average. The EIA forecasts average exports of 12.3 Bcf per day for the remainder of 2023 and 13.3 Bcf per day for 2024. The EIA forecast reflects the assumption that production remains flat and that expected additional U.S. LNG export capacity comes online.

How We Evaluate Our Operations

We use a variety of operational and financial measures to assess our performance. Among the measures considered by management are the following:

- volumes of oil and natural gas produced;
- commodity prices including the effect of derivative instruments; and
- Adjusted EBITDA and Distributable cash flow.

Volumes of Oil and Natural Gas Produced

In order to track and assess the performance of our assets, we monitor and analyze our production volumes from the various basins and plays that constitute our extensive asset base. We also regularly compare projected volumes to actual reported volumes and investigate unexpected variances.

Commodity Prices

<u>Factors Affecting the Sales Price of Oil and Natural Gas</u>

The prices we receive for oil, natural gas, and NGLs vary by geographical area. The relative prices of these products are determined by the factors affecting global and regional supply and demand dynamics, such as economic conditions, production levels, availability of transportation, weather cycles, and other factors. In addition, realized prices are influenced by product quality and proximity to consuming and refining markets. Any differences between realized prices and New York Mercantile Exchange ("NYMEX") prices are referred to as differentials. All our production is derived from properties located in the United States.

- *Oil*. The substantial majority of our oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. NYMEX light sweet crude oil, commonly referred to as West Texas Intermediate ("WTI"), is the prevailing domestic oil pricing index. The majority of our oil production is priced at the prevailing market price with the final realized price affected by both quality and location differentials.

  The chemical composition of oil plays an important role in its refining and subsequent sale as petroleum products. As a result, variations in chemical composition relative to the benchmark oil, usually WTI, will result in price adjustments, which are often referred to as quality differentials. The characteristics that most significantly affect quality differentials include the density of the oil, as characterized by its American Petroleum Institute (“API”) gravity, and the presence and concentration of impurities, such as sulfur.

  Location differentials generally result from transportation costs based on the produced oil’s proximity to consuming and refining markets and major trading points.

- *Natural Gas.* The NYMEX price quoted at Henry Hub is a widely used benchmark for the pricing of natural gas in the United States. The actual volumetric prices realized from the sale of natural gas differ from the quoted NYMEX price as a result of quality and location differentials.

  Quality differentials result from the heating value of natural gas measured in Btus and the presence of impurities, such as hydrogen sulfide, carbon dioxide, and nitrogen. Natural gas containing ethane and heavier hydrocarbons has a higher Btu value and will realize a higher volumetric price than natural gas which is predominantly methane, which has a lower Btu value. Natural gas with a higher concentration of impurities will realize a lower volumetric price due to the presence of the impurities in the natural gas when sold or the cost of treating the natural gas to meet pipeline quality specifications.

  Natural gas, which currently has a limited global transportation system, is subject to price variances based on local supply and demand conditions and the cost to transport natural gas to end user markets.

Hedging

We enter into derivative instruments to partially mitigate the impact of commodity price volatility on our cash generated from operations. From time to time, such instruments may include variable-to-fixed-price swaps, fixed-price contracts, costless collars, and other contractual arrangements. The impact of these derivative instruments could affect the amount of revenue we ultimately realize.

Our open derivative contracts consist of fixed-price swap contracts. Under fixed-price swap contracts, a counterparty is required to make a payment to us if the settlement price is less than the swap strike price. Conversely, we are required to make a payment to the counterparty if the settlement price is greater than the swap strike price. If we have multiple contracts outstanding with a single counterparty, unless restricted by our agreement, we will net settle the contract payments.

We may employ contractual arrangements other than fixed-price swap contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue. Our open oil and natural gas derivative contracts as of June 30, 2023 are detailed in Note 4 - Commodity Derivative Financial Instruments to our unaudited consolidated financial statements included elsewhere in this Quarterly Report.

Pursuant to the terms of our Credit Facility, we are allowed to hedge certain percentages of expected future monthly production volumes equal to the lesser of (i) internally forecasted production and (ii) the average of reported production for the most recent three months.

We are allowed, but not required, to hedge up to 90% of such volumes for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. As of June 30, 2023, we had hedged 74% and 62% of our available oil and condensate hedge volumes for 2023 and 2024, respectively. As of June 30, 2023, we had also hedged 67% and 82% of our available natural gas hedge volumes for 2023 and 2024, respectively.

We intend to continuously monitor the production from our assets and the commodity price environment, and will, from time to time, add additional hedges within the percentages described above related to such production. We do not enter into derivative instruments for speculative purposes.

Non-GAAP Financial Measures

Adjusted EBITDA and Distributable cash flow are supplemental non-GAAP financial measures used by our management and external users of our financial statements such as investors, research analysts, and others, to assess the financial performance of our assets and our ability to sustain distributions over the long term without regard to financing methods, capital structure, or historical cost basis.

We define Adjusted EBITDA as net income (loss) before interest expense, income taxes, and depreciation, depletion, and amortization adjusted for impairment of oil and natural gas properties, if any, accretion of asset retirement obligations, unrealized gains and losses on commodity derivative instruments, non-cash equity-based compensation, and gains and losses on sales of assets, if any. We define Distributable cash flow as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, cash interest expense, distributions to preferred unitholders, and restructuring charges, if any.

Adjusted EBITDA and Distributable cash flow should not be considered an alternative to, or more meaningful than, net income (loss), income (loss) from operations, cash flows from operating activities, or any other measure of financial performance presented in accordance with generally accepted accounting principles ("GAAP") in the United States as measures of our financial performance.

Adjusted EBITDA and Distributable cash flow have important limitations as analytical tools because they exclude some but not all items that affect net income (loss), the most directly comparable GAAP financial measure. Our computation of Adjusted EBITDA and Distributable cash flow may differ from computations of similarly titled measures of other companies.

The following table presents a reconciliation of net income (loss), the most directly comparable GAAP financial measure, to Adjusted EBITDA and Distributable cash flow for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2023	2022	2023	2022
	(in thousands)			
Net income (loss)	$ 78,392	$ 131,788	$ 212,835	$ 124,786
Adjustments to reconcile to Adjusted EBITDA:				
Depreciation, depletion, and amortization	10,421	11,893	21,568	22,810
Interest expense	645	1,362	1,459	2,571
Income tax expense (benefit)	139	(14)	286	89
Accretion of asset retirement obligations	250	205	495	407
Equity–based compensation	2,517	2,724	4,635	7,275
Unrealized (gain) loss on commodity derivative instruments	16,881	(35,103)	(22,105)	53,673
(Gain) loss on sale of assets, net	—	(17)	—	(17)
Adjusted EBITDA	109,245	112,838	219,173	211,594
Adjustments to reconcile to Distributable cash flow:				
Change in deferred revenue	(2)	(6)	(7)	(15)
Cash interest expense	(387)	(1,015)	(946)	(1,877)
Preferred unit distributions	(5,250)	(5,250)	(10,500)	(10,500)
Distributable cash flow	$ 103,606	$ 106,567	$ 207,720	$ 199,202

Results of Operations

Three Months Ended June 30, 2023 Compared to Three Months Ended June 30, 2022

The following table shows our production, revenue, and operating expenses for the periods presented:

	Three Months Ended June 30,			
	2023	2022	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	846	899	(53)	(5.9)%
Natural gas (MMcf)[1]	14,670	12,895	1,775	13.8 %
Equivalents (MBoe)	3,291	3,048	243	8.0 %
Equivalents/day (MBoe)	36.2	33.5	2.7	8.1 %
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 72.76	$ 104.89	$ (32.13)	(30.6)%
Natural gas ($/Mcf)[1]	2.84	8.62	(5.78)	(67.1)%
Equivalents ($/Boe)	$ 31.35	$ 67.41	$ (36.06)	(53.5)%
Revenue:				
Oil and condensate sales	$ 61,551	$ 94,296	$ (32,745)	(34.7)%
Natural gas and natural gas liquids sales[1]	41,619	111,181	(69,562)	(62.6)%
Lease bonus and other income	2,527	2,244	283	12.6 %
Revenue from contracts with customers	105,697	207,721	(102,024)	(49.1)%
Gain (loss) on commodity derivative instruments	11,303	(27,349)	38,652	(141.3)%
Total revenue	$ 117,000	$ 180,372	$ (63,372)	(35.1)%
Operating expenses:				
Lease operating expense	$ 2,866	$ 3,199	$ (333)	(10.4)%
Production costs and ad valorem taxes	12,844	19,504	(6,660)	(34.1)%
Exploration expense	4	2	2	100.0 %
Depreciation, depletion, and amortization	10,421	11,893	(1,472)	(12.4)%
General and administrative	11,854	12,519	(665)	(5.3)%
Other expense:				
Interest expense	645	1,362	(717)	(52.6)%

[1] As a mineral and royalty interest owner, we are often provided insufficient and inconsistent data on NGL volumes by our operators. As a result, we are unable to reliably determine the total volumes of NGLs associated with the production of natural gas on our acreage. Accordingly, no NGL volumes are included in our reported production; however, revenue attributable to NGLs is included in our natural gas revenue and our calculation of realized prices for natural gas.

Revenue

Total revenue for the quarter ended June 30, 2023 decreased compared to the quarter ended June 30, 2022. The decrease in total revenue from the corresponding period is primarily due to a decrease in oil and condensate sales and, natural gas and NGL sales, and was partially offset by a gain from our commodity derivative instruments compared to a loss in the prior period.

Oil and condensate sales. Oil and condensate sales decreased for the quarter ended June 30, 2023 as compared to the corresponding period in 2022 primarily due to lower realized commodity prices and production volumes. The decrease in oil and condensate production was driven by decreases in mineral and royalty production in the Permian Basin and the Eagle Ford. Our mineral and royalty interest oil and condensate volumes accounted for 93% and 92% of total oil and condensate volumes for quarters ended June 30, 2023 and 2022, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased for the quarter ended June 30, 2023 as compared to the corresponding prior period. The decrease was primarily due to lower realized commodity prices between the comparative periods partially offset by higher production volumes due to the timing of new development. The increase in natural gas and NGL production was primarily driven by new development in the Haynesville/Bossier play trend, including new activity from the Aethon development program in the Shelby Trough. Mineral and royalty interest production accounted for 93% and 90% of our natural gas volumes for the quarters ended June 30, 2023 and 2022, respectively.

Gain (loss) on commodity derivative instruments. During the second quarter of 2023, we recognized a gain from our commodity derivative instruments compared to a loss in the same period in 2022. Cash settlements we receive represent realized gains, while cash settlements we pay represent realized losses related to our commodity derivative instruments. In addition to cash settlements, we also recognize fair value changes on our commodity derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves. For the three months ended June 30, 2023, we recognized $28.2 million of realized gains and $16.9 million of unrealized losses from our oil and natural gas commodity contracts, compared to $62.5 million of realized losses and $35.1 million of unrealized gains in the same period in 2022. The unrealized losses on our commodity contracts during the second quarter of 2023 were primarily driven by changes in the forward commodity price curves for natural gas. The unrealized gains for the same period in 2022 were primarily driven by changes in the forward commodity price curves for natural gas.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus revenue can vary substantively between periods because it is derived from individual transactions with operators, some of which may be significant. Lease bonus and other income for the second quarter of 2023 was higher than the same period in 2022. Leasing activity in the Bakken/Three Forks and Haynesville/Bossier plays made up the majority of lease bonus and other income for the second quarter of 2023, while the majority of the second quarter 2022 activity came from leasing activity in the Austin Chalk play.

Operating Expenses

Lease operating expense. Lease operating expense includes recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased for the quarter ended June 30, 2023 as compared to the same period in 2022, primarily due to lower nonrecurring service-related expenses, including workovers.

Production costs and ad valorem taxes. Production taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the regulations of the states where the production originates, these taxes may be based on a percentage of the realized value or a fixed amount per production unit. This category also includes the costs to process and transport our production to applicable sales points. Ad valorem taxes are jurisdictional taxes levied on the value of oil and natural gas minerals and reserves. Rates, methods of calculating property values, and timing of payments vary between taxing authorities. For the quarter ended June 30, 2023, production costs and ad valorem taxes decreased as compared to the quarter ended June 30, 2022, primarily due to lower production taxes and lower ad valorem tax estimates stemming from lower commodity prices.

Exploration expense. Exploration expense typically consists of dry-hole expenses, delay rentals, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense was minimal for the quarter ended June 30, 2023 and in the corresponding prior period in 2022.

Depreciation, depletion, and amortization. Depletion is the amount of cost basis of oil and natural gas properties attributable to the volume of hydrocarbons extracted during a period, calculated on a units-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We adjust our depletion rates semi-annually based upon mid-year and year-end reserve reports, except when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization decreased for the quarter ended June 30, 2023 as compared to the same period in 2022, primarily due to a reduction in cost basis with a lower corresponding reduction in proved developed producing reserve quantities partially offset by increased production. The reduction in cost basis is primarily due to depreciation, depletion, and amortization recorded during the prior twelve months.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and include expenses such as the cost of employee salaries and related benefits, office expenses, and fees for professional services. For the quarter ended June 30, 2023, general and administrative expenses decreased slightly as compared to the same period in 2022, primarily due to a $0.8 million decrease in cash compensation. The decrease in cash compensation was driven by projected underperformance relative to performance targets under our short-term cash incentive plan compared with projected overperformance in the prior period.

Interest expense. Interest expense was lower in the second quarter of 2023 relative to the corresponding period in 2022, primarily due to lower average outstanding borrowings under our Credit Facility.

Six Months Ended June 30, 2023 Compared to Six Months Ended June 30, 2022

The following table shows our production, revenues, pricing, and expenses for the periods presented:

	Six Months Ended June 30,						
	2023		2022		Variance		
	(Dollars in thousands, except for realized prices)						
Production:							
Oil and condensate (MBbls)		1,639		1,730		(91)	(5.3)%
Natural gas (MMcf)[1]		31,121		25,654		5,467	21.3 %
Equivalents (MBoe)		6,826		6,006		820	13.7 %
Equivalents/day (MBoe)		37.7		33.2		4.5	13.6 %
Realized prices, without derivatives:							
Oil and condensate ($/Bbl)	$	74.72	$	98.34	$	(23.62)	(24.0)%
Natural gas ($/Mcf)[1]		3.18		7.29		(4.11)	(56.4)%
Equivalents ($/Boe)	$	32.45	$	59.45	$	(27.00)	(45.4)%
Revenue:							
Oil and condensate sales	$	122,460	$	170,127	$	(47,667)	(28.0)%
Natural gas and natural gas liquids sales[1]		99,042		186,935		(87,893)	(47.0)%
Lease bonus and other income		6,502		7,103		(601)	(8.5)%
Revenue from contracts with customers		228,004		364,165		(136,161)	(37.4)%
Gain (loss) on commodity derivative instruments		63,574		(147,369)		210,943	143.1 %
Total revenue	$	291,578	$	216,796	$	74,782	34.5 %
Operating expenses:							
Lease operating expense	$	5,534	$	6,360	$	(826)	(13.0)%
Production costs and ad valorem taxes		25,511		33,453		(7,942)	(23.7)%
Exploration expense		8		182		(174)	(95.6)%
Depreciation, depletion, and amortization		21,568		22,810		(1,242)	(5.4)%
General and administrative		24,502		26,282		(1,780)	(6.8)%
Other expense:							
Interest expense		1,459		2,571		(1,112)	(43.3)%

[1] As a mineral and royalty interest owner, we are often provided insufficient and inconsistent data on NGL volumes by our operators. As a result, we are unable to reliably determine the total volumes of NGLs associated with the production of natural gas on our acreage. Accordingly, no NGL volumes are included in our reported production; however, revenue attributable to NGLs is included in our natural gas revenue and our calculation of realized prices for natural gas.

Revenue

Total revenue for the six months ended June 30, 2023 increased compared to the corresponding prior period. The increase in total revenue is due to a gain from our commodity derivative instruments for the six months ended June 30, 2023 compared to a loss in the same period in 2022. The overall increase in total revenue was partially offset by decreases in oil and condensate sales, natural gas and NGL sales, and lease bonus and other income.

Oil and condensate sales. Oil and condensate sales during the six months ended June 30, 2023 decreased compared to the corresponding prior period due to lower realized commodity prices and a decrease in production. The decrease in oil and condensate production was driven by decreases in mineral and royalty production in the Permian Basin and the Eagle Ford. Our mineral and royalty interest oil and condensate volumes accounted for 93% of total oil and condensate volumes for both the six months ended June 30, 2023 and 2022.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the six months ended June 30, 2023 decreased compared to the corresponding prior period due to lower realized commodity prices partially offset by higher production volumes. The increase in natural gas and NGL production was driven by increases in royalty interest production volumes, primarily within the Haynesville/Bossier play, including new activity from the Aethon development program in the Shelby Trough. Mineral and royalty interest production accounted for 94% and 89% of our natural gas volumes for the six months ended June 30, 2023 and 2022, respectively.

Gain (loss) on commodity derivative instruments. During the six months ended June 30, 2023, we recognized a gain from our commodity derivative instruments compared to a loss for the same period in 2022. In the six months ended June 30, 2023, we recognized $41.5 million of realized gains and $22.1 million of unrealized gains from our oil and natural gas commodity contracts, compared to $93.7 million of realized losses and $53.7 million of unrealized losses in the same period in 2022. The unrealized gains on our commodity contracts during the six months ended June 30, 2023 were primarily driven by changes in the forward commodity price curves for oil and natural gas. The unrealized losses on our commodity contracts during the corresponding period in 2022 were primarily driven by changes in the forward commodity price curves for oil and natural gas.

Lease bonus and other income. Lease bonus and other income for the six months ended June 30, 2023 was lower than the same period in 2022. Leasing activity in the Bakken/Three Forks and Haynesville/Bossier plays made up the majority of lease bonus and other income for the six months ended June 30, 2023, while a substantial portion of the activity in the corresponding prior period came from leasing activity in the Wolfcamp play.

<u>Operating and Other Expenses</u>

Lease operating expense. Lease operating expense decreased for the six months ended June 30, 2023 as compared to the same period in 2022, primarily due to lower nonrecurring service-related expenses, including workovers.

Production costs and ad valorem taxes. For the six months ended June 30, 2023, production costs and ad valorem taxes decreased as compared to the six months ended June 30, 2022, primarily due to lower production taxes stemming from lower commodity prices and lower ad valorem tax estimates.

Exploration expense. Exploration expense was minimal for the six months ended June 30, 2023 and for the six months ended June 30, 2022.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization decreased slightly for the six months ended June 30, 2023 as compared to the same period in 2022, primarily due to a reduction in cost basis with a lower corresponding reduction in proved developed producing reserve quantities partially offset by increased production. The reduction in cost basis is primarily due to depreciation, depletion, and amortization recorded during the prior twelve months.

General and administrative. For the six months ended June 30, 2023, general and administrative expenses decreased as compared to the same period in 2022, primarily due to a $2.6 million decrease in equity compensation which was partially offset by a $1.0 million increase in cash compensation. The increase in cash compensation was driven by an increase in salaries as well as a separation payment related to the departure of a senior executive in the first quarter of 2023. The overall increase in cash compensation was partially offset by projected underperformance relative to performance targets under our short-term cash incentive plan compared with projected overperformance in the prior period. The decrease in equity incentive compensation was due to lower costs recognized for performance-based incentive awards resulting from downward movements in our common unit price during the six months ended June 30, 2023 compared to upward movements in our common unit price in the corresponding prior period.

Interest expense. Interest expense was lower in the six months ended June 30, 2023 than in the prior period primarily due to lower average outstanding borrowings under our Credit Facility.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations, borrowings under our Credit Facility, and proceeds from the issuance of equity and debt. Our primary uses of cash are for distributions to our unitholders, reducing outstanding borrowings under our Credit Facility, and for investing in our business, specifically the acquisition of mineral and royalty interests and our selective participation on a non-operated working interest basis in the development of our oil and natural gas properties. As of June 30, 2023, no balance was outstanding under the Credit Facility. We have the option to redeem Series B cumulative convertible preferred units beginning on November 28, 2023. See Note 9 to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

The Board has adopted a policy pursuant to which, at a minimum, distributions will be paid on each common unit for each quarter to the extent we have sufficient cash generated from our operations after establishment of cash reserves, if any, and after we have made the required distributions to the holders of our outstanding preferred units. However, we do not have a legal or contractual obligation to pay distributions on our common units quarterly or on any other basis, and there is no guarantee that we will pay distributions to our common unitholders in any quarter. The Board may change the foregoing distribution policy at any time and from time to time.

We intend to finance any future acquisitions with cash generated from operations, borrowings from our Credit Facility, proceeds from any future issuances of equity and debt, and proceeds from asset sales. Over the long-term, we intend to finance our working interest capital needs with our executed farmout agreements and internally generated cash flows, although at times we may fund a portion of these expenditures through other financing sources such as borrowings under our Credit Facility.

Cash Flows

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

	Six Months Ended June 30,		
	2023	2022	Change
	(in thousands)		
Cash flows provided by operating activities	$ 270,425	$ 160,139	$ 110,286
Cash flows used in investing activities	(2,633)	(145)	(2,488)
Cash flows used in financing activities	(225,433)	(156,712)	(68,721)

Operating Activities. Our operating cash flows are dependent, in large part, on our production, realized commodity prices, derivative settlements, lease bonus revenue, and operating expenses. Cash flows provided by operating activities increased for the six months ended June 30, 2023 as compared to the same period of 2022. The increase was primarily due to higher cash settlements received on our commodity derivative instruments as compared to cash settlements paid in the same period of 2022.

Investing Activities. Net cash used in investing activities in the six months ended June 30, 2023 increased as compared to the same period of 2022. The increase was primarily due to increased additions to oil and natural gas properties, net of farmout reimbursements in the six months ended June 30, 2023 as compared to the corresponding prior period.

Financing Activities. Cash flows used in financing activities increased for the six months ended June 30, 2023 as compared to the same period of 2022. The increase was primarily due to higher distributions to unitholders in the six months ended June 30, 2023 as compared to the corresponding prior period.

Development Capital Expenditures

Our 2023 capital expenditure budget associated with our non-operated working interests is expected to be approximately $4.9 million, net of farmout reimbursements, of which $2.5 million has been invested in the six months ended June 30, 2023. The majority of this capital is anticipated to be spent for workovers and recompletions on existing wells in which we own a working interest.

Credit Facility

We maintain a senior secured revolving credit agreement, as amended, (the "Credit Facility"). The Credit Facility has an aggregate maximum credit amount of $1.0 billion. The commitment of the lenders equals the least of the aggregate maximum credit amount, the then-effective borrowing base, and the aggregate elected commitment, as it may be adjusted from time to time. Borrowings under the Credit Facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Our Credit Facility terminates on October 31, 2027. As of June 30, 2023, no balance was outstanding under the Credit Facility.

The borrowing base is redetermined semi-annually, usually in April and October and is derived from the value of our oil and natural gas properties as determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. We and the lenders (at the direction of two-thirds of the lenders) each have discretion to request a borrowing base redetermination one time between scheduled redeterminations. We also have the right to request a redetermination following the acquisition of oil and natural gas properties in excess of 10% of the value of the borrowing base immediately prior to such acquisition. The borrowing base is also adjusted if we terminate our hedge positions or sell oil and natural gas property interests that have a combined value exceeding 5% of the current borrowing base. In these circumstances, the borrowing base will be adjusted by the value attributed to the terminated hedge positions or the oil and natural gas property interests sold in the most recent borrowing base. The April and October 2021 and April 2022 borrowing base redeterminations reaffirmed the borrowing base at $400.0 million. In October 2022, we revised and amended the Credit Facility to extend the maturity date from November 1, 2024 to October 31, 2027. Concurrent with the Credit Facility amendment, the borrowing base under the Credit Facility was increased to $550.0 million and we elected to lower commitments under the Credit Facility from $400.0 million to $375.0 million. The April 2023 borrowing base redetermination reaffirmed the borrowing base at $550.0 million with cash commitments at $375.0 million. The next semi-annual redetermination is scheduled for October 2023.

In October 2022, the Credit Facility was amended to replace the LIBOR rate with the secured overnight financing rate published by the Federal Reserve Bank of New York ("SOFR"). Outstanding borrowings under the Credit Facility bear interest at a floating rate elected by us equal to a base rate (which is a rate per annum equal to the highest of (a) the Prime Rate in effect on such day, (b) the Federal Funds Rate in effect on such day plus 0.50%, and (c) Adjusted Term SOFR for a one month tenor in effect on such day plus 1.00%) or Adjusted Term SOFR, in each case, plus the applicable margin. As of December 31, 2022 and June 30, 2023, the applicable margin for the alternative base rate ranged from 1.50% to 2.50% and the Adjusted Term SOFR margin ranged from 2.50% to 3.50%, depending on the borrowings outstanding in relation to the borrowing base.

We are obligated to pay a quarterly commitment fee ranging from a 0.375% to 0.500% annualized rate on the unused portion of the borrowing base, depending on the amount of the borrowings outstanding in relation to the borrowing base. Principal may be optionally repaid from time to time without premium or penalty, other than customary SOFR breakage, and is required to be paid (a) if the amount outstanding exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise, in some cases subject to a cure period, or (b) at the maturity date. Our Credit Facility is secured by substantially all of our oil and natural gas production and assets.

Our credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates, and entering into certain derivative agreements, as well as require the maintenance of certain financial ratios. The credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less and a current ratio of 1.0:1.0 or greater as defined in the credit agreement. Distributions are not permitted if there is a default under the credit agreement (including the failure to satisfy one of the financial covenants), if the availability under the Credit Facility is less than 10% of the lenders' commitments, or if total debt to EBITDAX is greater than 3.0. The lenders have the right to accelerate all of the indebtedness under the credit agreement upon the occurrence and during the continuance of any event of default, and the credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of June 30, 2023, we were in compliance with all debt covenants.

Contractual Obligations

As of June 30, 2023, there have been no material changes to our contractual obligations previously disclosed in our 2022 Annual Report on Form 10-K.

Critical Accounting Policies and Related Estimates

As of June 30, 2023, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2022 Annual Report on Form 10-K.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil, natural gas, and NGLs produced by our operators. Realized prices are primarily driven by the prevailing global prices for oil and prices for natural gas and NGLs in the United States. Prices for oil, natural gas, and NGLs have been historically volatile, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control. To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we use commodity derivative instruments to reduce our exposure to price volatility of oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settle monthly in cash based on a designated floating price. The designated floating price is based on the NYMEX benchmark for oil and natural gas. We have not designated any of our contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in net income in the period of the change. See Note 4 - Commodity Derivative Financial Instruments and Note 5 - Fair Value Measurements to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Commodity prices have been historically volatile based upon the dynamics of supply and demand. To estimate the effect lower prices would have on our reserves, we reduced the SEC commodity pricing for the three months ended June 30, 2023 by 10%. This results in an approximate 1% reduction of proved reserve volumes as compared to the unadjusted June 30, 2023 SEC pricing scenario.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty’s credit rating and latest financial information. As of June 30, 2023, we had seven counterparties, all of which were rated Baa1 or better by Moody’s and are lenders under our Credit Facility.

Our principal exposure to credit risk results from receivables generated by the production activities of our operators. The inability or failure of our significant operators to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit risk associated with our operators and customers is acceptable.

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. During the six months ended June 30, 2023, we had $6.9 million weighted average outstanding borrowings under our Credit Facility, bearing interest at a weighted average interest rate of 7.30%. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of less than $0.1 million for the six months ended June 30, 2023, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the “Exchange Act”), we have evaluated, under the supervision and with the participation of management of our general partner, including our general partner’s principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our general partner’s principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our general partner’s principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2023 to provide reasonable assurance.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2023 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows, or results of operations.

Item 1A. Risk Factors

In addition to the other information set forth in this report, readers should carefully consider the risks under the heading “Risk Factors” in our 2022 Annual Report on Form 10-K. Except to the extent updated below, there has been no material change in our risk factors from those described in our 2022 Annual Report on Form 10-K. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

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

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

None.

Item 5. Other Information

During the three months ended June 30, 2023, none of our directors or executive officers adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408(a) of Regulation S-K.

Item 6. Exhibits

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.1 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.2	Certificate of Amendment to Certificate of Limited Partnership of Black Stone Minerals, L.P. (incorporated herein by reference to Exhibit 3.2 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
3.3	First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated May 6, 2015, by and among Black Stone Minerals GP, L.L.C. and Black Stone Minerals Company, L.P., (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on May 6, 2015 (SEC File No. 001-37362)).
3.4	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of April 15, 2016 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)).
3.5	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of November 28, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
3.6	Amendment No. 3 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of December 11, 2017 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on December 12, 2017 (SEC File No. 001-37362)).
3.7	Amendment No. 4 to First Amended and Restated Agreement of Limited Partnership of the Black Stone Minerals, L.P., dated as of April 22, 2020 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 24, 2020 (SEC File No. 001-37362)).
4.1	Registration Rights Agreement, dated as of November 28, 2017, by and between Black Stone Minerals, L.P. and Mineral Royalties One, L.L.C. (incorporated herein by reference to Exhibit 4.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on November 29, 2017 (SEC File No. 001-37362)).
31.1*	Certification of Chief Executive Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer of Black Stone Minerals, L.P. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification of Chief Executive Officer and Chief Financial Officer of Black Stone Minerals, L.P. 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 Schema Document
101.CAL*	Inline XBRL Calculation Linkbase Document
101.LAB*	Inline XBRL Label Linkbase Document
101.PRE*	Inline XBRL Presentation Linkbase Document
101.DEF*	Inline XBRL Definition Linkbase Document
104*	Cover Page Interactive Data File - the cover page iXBRL tags are embedded within the Inline XBRL document.

* Filed or 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.

	BLACK STONE MINERALS, L.P.	
	By:	Black Stone Minerals GP, L.L.C., its general partner
Date: August 1, 2023	By:	/s/ Thomas L. Carter, Jr.
		Thomas L. Carter, Jr. Chief Executive Officer, President, and Chairman (Principal Executive Officer)
Date: August 1, 2023	By:	/s/ Evan M. Kiefer
		Evan M. Kiefer Interim Chief Financial Officer and Treasurer (Principal Financial Officer)

Exhibit 31.1

Certification of Chief Executive Officer
pursuant to Rule 13a-14(a) and Rule 15d-14(a)
of the Securities Exchange Act of 1934, as amended

I, Thomas L. Carter, Jr., certify that:

1. I have reviewed this report on Form 10-Q of Black Stone Minerals, L.P. (the “registrant”);

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 officers 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 officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 1, 2023

/s/ Thomas L. Carter, Jr.
Thomas L. Carter, Jr.
Chief Executive Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Exhibit 31.2

Certification of Chief Financial Officer
pursuant to Rule 13a-14(a) and Rule 15d-14(a)
of the Securities Exchange Act of 1934, as amended

I, Evan M. Kiefer, certify that:

1. I have reviewed this report on Form 10-Q of Black Stone Minerals, L.P. (the “registrant”);

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 officers 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 officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: August 1, 2023

/s/ Evan M. Kiefer
Evan M. Kiefer
Interim Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Exhibit 32.1

Certification of
Chief Executive Officer and Chief Financial Officer
under Section 906 of the
Sarbanes Oxley Act of 2002, 18 U.S.C. § 1350

In connection with the report on Form 10-Q of Black Stone Minerals, L.P. (the "Partnership"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Thomas L. Carter, Jr., Chief Executive Officer of the Partnership, and Evan M. Kiefer, Interim Chief Financial Officer of the Partnership, each certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) the Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

Date: August 1, 2023

/s/ Thomas L. Carter, Jr.
Thomas L. Carter, Jr.
Chief Executive Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.

Date: August 1, 2023

/s/ Evan M. Kiefer
Evan M. Kiefer
Interim Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.