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, 2025

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 August 1, 2025, there were 211,852,971 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. Condensed Financial Statements

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

	June 30, 2025	December 31, 2024
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 2,519	$ 2,519
Accrued revenue and accounts receivable	80,025	71,093
Commodity derivative assets, net	2,111	1,824
Prepaid expenses and other current assets	8,731	3,108
TOTAL CURRENT ASSETS	93,386	78,544
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $1,015,395 and $973,028 at June 30, 2025 and December 31, 2024, respectively	3,153,976	3,105,457
Accumulated depletion and impairment	(1,989,690)	(1,973,460)
Oil and natural gas properties, net	1,164,286	1,131,997
Other property and equipment, net of accumulated depreciation of $15,238 and $14,551 at June 30, 2025 and December 31, 2024, respectively	1,508	2,044
NET PROPERTY AND EQUIPMENT	1,165,794	1,134,041
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	8,709	6,321
TOTAL ASSETS	$ 1,267,889	$ 1,218,906
LIABILITIES, MEZZANINE EQUITY, AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 6,877	$ 5,946
Accrued liabilities	12,504	17,242
Commodity derivative liabilities, net	7,072	3,852
Other current liabilities	2,528	3,383
TOTAL CURRENT LIABILITIES	28,981	30,423
LONG–TERM LIABILITIES		
Credit facility	99,000	25,000
Accrued incentive compensation	788	1,234
Commodity derivative liabilities, net	11,766	11,581
Asset retirement obligations	19,728	19,286
Other long-term liabilities	5,010	1,943
TOTAL LIABILITIES	165,273	89,467
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity – Series B cumulative convertible preferred units, 14,711 units outstanding at June 30, 2025 and December 31, 2024	300,478	300,478
EQUITY		
Partners' equity – general partner interest	—	—
Partners' equity – common units, 211,842 and 210,695 units outstanding at June 30, 2025 and December 31, 2024, respectively	802,138	828,961
TOTAL EQUITY	802,138	828,961
TOTAL LIABILITIES, MEZZANINE EQUITY, AND EQUITY	$ 1,267,889	$ 1,218,906

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,	
	2025	2024	2025	2024
REVENUE				
Oil and condensate sales	$ 55,807	$ 73,889	$ 105,900	$ 145,113
Natural gas and natural gas liquids sales	46,189	36,493	104,424	78,504
Lease bonus and other income	4,714	4,789	11,639	8,337
Revenue from contracts with customers	106,710	115,171	221,963	231,954
Gain (loss) on commodity derivative instruments	52,784	(5,547)	(3,217)	(16,837)
TOTAL REVENUE	159,494	109,624	218,746	215,117
OPERATING (INCOME) EXPENSE				
Lease operating expense	2,990	2,579	5,152	5,011
Production costs and ad valorem taxes	9,026	13,469	19,211	26,507
Exploration expense	1,749	14	6,859	17
Depreciation, depletion, and amortization	9,187	11,356	18,317	22,995
General and administrative	13,924	13,395	29,096	27,485
Accretion of asset retirement obligations	337	321	669	638
TOTAL OPERATING EXPENSE	37,213	41,134	79,304	82,653
INCOME FROM OPERATIONS	122,281	68,490	139,442	132,464
OTHER INCOME (EXPENSE)				
Interest and investment income	56	462	120	1,132
Interest expense	(2,270)	(626)	(3,667)	(1,255)
Other income (expense)	(39)	(4)	81	(92)
TOTAL OTHER EXPENSE	(2,253)	(168)	(3,466)	(215)
NET INCOME	120,028	68,322	135,976	132,249
Distributions on Series B cumulative convertible preferred units	(7,367)	(7,366)	(14,733)	(14,733)
NET INCOME ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 112,661	$ 60,956	$ 121,243	$ 117,516
ALLOCATION OF NET INCOME:				
General partner interest	$ —	$ —	$ —	$ —
Common units	112,661	60,956	121,243	117,516
	$ 112,661	$ 60,956	$ 121,243	$ 117,516
NET INCOME ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:				
Per common unit (basic)	$ 0.53	$ 0.29	$ 0.57	$ 0.56
Per common unit (diluted)	$ 0.53	$ 0.29	$ 0.57	$ 0.56
WEIGHTED AVERAGE COMMON UNITS OUTSTANDING:				
Weighted average common units outstanding (basic)	211,689	210,703	211,472	210,679
Weighted average common units outstanding (diluted)	226,761	210,703	211,472	210,679

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, 2024	210,695	$ 828,961
Repurchases of common units	(221)	(3,289)
Issuance of common units for property acquisitions	256	3,905
Restricted units granted, net of forfeitures	900	—
Equity–based compensation	—	5,919
Distributions	—	(79,177)
Charges to partners' equity for accrued distribution equivalent rights	—	(414)
Distributions on Series B cumulative convertible preferred units	—	(7,366)
Net income	—	15,948
BALANCE AT MARCH 31, 2025	211,630	$ 764,487
Repurchases of common units	(36)	(466)
Issuance of common units for property acquisitions	253	3,512
Restricted units granted, net of forfeitures	(5)	—
Equity–based compensation	—	1,691
Distributions	—	(79,363)
Charges to partners' equity for accrued distribution equivalent rights	—	(384)
Distributions on Series B cumulative convertible preferred units	—	(7,367)
Net income	—	120,028
BALANCE AT JUNE 30, 2025	211,842	$ 802,138

	Common units	Partners' equity
BALANCE AT DECEMBER 31, 2023	209,991	$ 918,208
Repurchases of common units	(287)	(4,381)
Restricted units granted, net of forfeitures	952	—
Equity–based compensation	—	5,431
Distributions	—	(99,899)
Charges to partners' equity for accrued distribution equivalent rights	—	(595)
Distributions on Series B cumulative convertible preferred units	—	(7,367)
Net income	—	63,927
BALANCE AT MARCH 31, 2024	210,656	$ 875,324
Repurchases of common units	(4)	(68)
Issuance of common units for property acquisitions	64	1,039
Restricted units granted, net of forfeitures	(34)	—
Equity–based compensation	—	1,935
Distributions	—	(79,014)
Charges to partners' equity for accrued distribution equivalent rights	—	(185)
Distributions on Series B cumulative convertible preferred units	—	(7,366)
Net income	—	68,322
BALANCE AT JUNE 30, 2024	210,682	$ 859,987

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,	
	2025	**2024**
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$ 135,976	$ 132,249
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, and amortization	18,317	22,995
Accretion of asset retirement obligations	669	638
Amortization of deferred charges	550	536
(Gain) loss on commodity derivative instruments	3,217	16,837
Net cash (paid) received on settlement of commodity derivative instruments	(465)	25,616
Equity-based compensation	5,015	4,588
Changes in operating assets and liabilities:		
Accrued revenue and accounts receivable	(8,948)	8,481
Prepaid expenses and other current assets	(5,623)	(737)
Accounts payable, accrued liabilities, and other	(3,297)	(5,990)
Settlement of asset retirement obligations	(100)	(368)
NET CASH PROVIDED BY OPERATING ACTIVITIES	145,311	204,845
CASH FLOWS FROM INVESTING ACTIVITIES		
Acquisitions of oil and natural gas properties	(37,990)	(49,478)
Additions to oil and natural gas properties	(326)	(388)
Additions to oil and natural gas properties leasehold costs	(4,620)	(1,839)
Purchases of other property and equipment	(151)	(55)
Proceeds from the sale of oil and natural gas properties	400	79
NET CASH USED IN INVESTING ACTIVITIES	(42,687)	(51,681)
CASH FLOWS FROM FINANCING ACTIVITIES		
Distributions to common unitholders	(158,540)	(178,913)
Distributions to Series B cumulative convertible preferred unitholders	(14,733)	(13,393)
Repurchases of common units	(3,289)	(4,449)
Borrowings under credit facility	179,000	9,000
Repayments under credit facility	(105,000)	(9,000)
Debt issuance costs and other	(62)	(22)
NET CASH USED IN FINANCING ACTIVITIES	(102,624)	(196,777)
NET CHANGE IN CASH AND CASH EQUIVALENTS	—	(43,613)
CASH AND CASH EQUIVALENTS – beginning of the period	2,519	70,282
CASH AND CASH EQUIVALENTS – end of the period	$ 2,519	$ 26,669
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 2,939	$ 719
Common units issued for property acquisitions	$ 7,417	$ 1,039

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 condensed 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, 2024 ("2024 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, 2025 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 in the accompanying unaudited interim consolidated financial statements.

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 reportable segment. The Partnership generates revenue from the sale of oil and natural gas, as well as lease bonus and other income that is derived from our oil and natural gas properties. These properties are all located within the continental U.S., including all of the major onshore producing basins. Reportable segments are defined as components of an enterprise for which separate financial information is evaluated regularly by the chief operating decision maker ("CODM") in deciding how to allocate resources and assess performance. The Partnership's chief executive officer has been determined to be the CODM and allocates resources and assesses performance based upon net income reported on the consolidated statements of operations. The measure of segment assets is reported on the consolidated balance sheets as total assets. The CODM uses net income to evaluate the income generated from segment assets in deciding whether to reinvest profits into the Partnership's oil and natural gas properties or for other activities such as distributions to unitholders and reducing outstanding borrowings as applicable.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies

Significant accounting policies are disclosed in the Partnership’s 2024 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, 2025.

Accrued Revenue and Accounts Receivable

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

	June 30, 2025	December 31, 2024
	(in thousands)	
Accrued revenue	$ 74,577	$ 67,047
Accounts receivable	5,448	4,046
Total accrued revenue and accounts receivable	$ 80,025	$ 71,093

Recent Accounting Pronouncements

In November 2024, the FASB issued ASU 2024-03, Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures, which enhances the disclosures required for certain expense captions in the Partnership's annual and interim consolidated financial statements. The guidance is effective for fiscal years beginning after December 15, 2026 and for interim periods beginning after December 15, 2027, with early adoption permitted. The Partnership is currently evaluating the impact of this standard on its disclosures.

NOTE 3 - OIL AND NATURAL GAS PROPERTIES

Acquisitions

During the six months ended June 30, 2025, the Partnership acquired mineral and royalty interests that consisted of primarily unproved oil and natural gas properties in the Gulf Coast land region from various sellers for an aggregate of $45.4 million, including capitalized direct transaction costs, and were considered asset acquisitions. The consideration paid consisted of $38.0 million in cash that was funded from operating activities and $7.4 million in equity that was funded through the issuance of common units of the Partnership based on the fair values of the common units issued on the acquisition dates.

During the year ended December 31, 2024, the Partnership acquired mineral and royalty interests that consisted of unproved oil and natural gas properties in the Gulf Coast land region from various sellers for an aggregate of $110.4 million, including capitalized direct transaction costs, and were considered asset acquisitions. The cash portion of the consideration paid of $109.4 million was funded with borrowings under our Credit Facility and funds from operating activities, and $1.0 million in equity that was funded through the issuance of common units of the Partnership based on the fair value of the common units issued on the acquisition date.

Asset Exchanges

The Partnership completed multiple asset exchange transactions to consolidate a concentrated acreage position in East Texas. These transactions, which are described below, involved partial dispositions of unproved property, and no gains or losses were recognized.

In March 2025, the Partnership closed on a transaction with a third-party operator whereby the Partnership acquired an oil and natural gas lease on approximately 2,900 net leasehold acres in East Texas in exchange for the assignment of approximately 900 undeveloped net mineral and royalty acres in Louisiana.

In February 2025, the Partnership closed on a transaction with a third-party operator whereby the Partnership exchanged oil and natural gas leases covering certain acreage in East Texas. The Partnership acquired approximately 2,100 net leasehold acres in exchange for approximately 3,700 net leasehold acres.

In July 2024, the Partnership closed on a transaction with a third-party operator whereby the Partnership acquired an oil and natural gas lease on approximately 8,000 net leasehold acres in East Texas in exchange for the assignment of approximately 51,000 undeveloped net mineral and royalty acres in Mississippi.

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, 2025, 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 statements 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, 2025 and December 31, 2024. See "Note 5 - Fair Value Measurements" for additional information.

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, 2025, the Partnership had seven counterparties that also serve as 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, 2025		
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, net	$ 12,829	$ (10,718)	$ 2,111
Long-term asset	Deferred charges and other long-term assets	3,652	(3,286)	366
Total assets		$ 16,481	$ (14,004)	$ 2,477
Liabilities:				
Current liability	Commodity derivative liabilities, net	$ 17,790	$ (10,718)	$ 7,072
Long-term liability	Commodity derivative liabilities, net	15,052	(3,286)	11,766
Total liabilities		$ 32,842	$ (14,004)	$ 18,838

		December 31, 2024		
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, net	$ 4,866	$ (3,042)	$ 1,824
Long-term asset	Deferred charges and other long-term assets	768	(768)	—
Total assets		$ 5,634	$ (3,810)	$ 1,824
Liabilities:				
Current liability	Commodity derivative liabilities, net	$ 6,894	$ (3,042)	$ 3,852
Long-term liability	Commodity derivative liabilities, net	12,349	(768)	11,581
Total liabilities		$ 19,243	$ (3,810)	$ 15,433

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:

Derivatives not designated as hedging instruments	Three Months Ended June 30, 2025	Three Months Ended June 30, 2024	Six Months Ended June 30, 2025	Six Months Ended June 30, 2024
	(in thousands)			
Beginning fair value of commodity derivative instruments	$ (65,999)	$ 12,248	$ (13,609)	$ 37,335
Gain (loss) on oil derivative instruments	17,224	(1,226)	16,411	(24,456)
Gain (loss) on natural gas derivative instruments	35,560	(4,321)	(19,628)	7,619
Net cash paid (received) on settlements of oil derivative instruments	(4,038)	5,526	(3,656)	5,405
Net cash paid (received) on settlements of natural gas derivative instruments	892	(17,345)	4,121	(31,021)
Net change in fair value of commodity derivative instruments	49,638	(17,366)	(2,752)	(42,453)
Ending fair value of commodity derivative instruments	$ (16,361)	$ (5,118)	$ (16,361)	$ (5,118)

The Partnership had the following open derivative contracts for oil as of June 30, 2025:

Period and Type of Contract	Volume (Bbl)	Weighted Average Price (Per Bbl)	Range (Per Bbl) Low	Range (Per Bbl) High
Oil Swap Contracts:				
2025				
Second Quarter	185,000	$ 71.22	$ 70.02	$ 73.15
Third Quarter	555,000	71.22	70.02	73.15
Fourth Quarter	555,000	71.22	70.02	73.15
2026				
First Quarter	480,000	$ 64.80	$ 62.63	$ 67.35
Second Quarter	480,000	64.80	62.63	67.35
Third Quarter	480,000	64.80	62.63	67.35
Fourth Quarter	480,000	64.80	62.63	67.35

The Partnership had the following open derivative contracts for natural gas as of June 30, 2025:

Period and Type of Contract	Volume (MMBtu)	Weighted Average Price (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2025				
Third Quarter	11,040,000	$ 3.45	$ 3.34	$ 3.65
Fourth Quarter	11,040,000	3.45	3.34	3.65
2026				
First Quarter	11,700,000	$ 3.67	$ 3.50	$ 4.05
Second Quarter	11,830,000	3.67	3.50	4.05
Third Quarter	11,960,000	3.67	3.50	4.05
Fourth Quarter	11,960,000	3.67	3.50	4.05

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. There were no transfers into, or out of, the three levels of fair value hierarchy for the six months ended June 30, 2025 and 2024.

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, 2025 and December 31, 2024 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 additional information.

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

	Fair Value Measurements Using					
	Level 1	Level 2	Level 3	Effect of Counterparty Netting	Total
	(in thousands)				
As of June 30, 2025					
Financial Assets					
Commodity derivative instruments	$ —	$ 16,481	$ —	$ (14,004)	$ 2,477
Financial Liabilities					
Commodity derivative instruments	$ —	$ 32,842	$ —	$ (14,004)	$ 18,838
As of December 31, 2024					
Financial Assets					
Commodity derivative instruments	$ —	$ 5,634	$ —	$ (3,810)	$ 1,824
Financial Liabilities					
Commodity derivative instruments	$ —	$ 19,243	$ —	$ (3,810)	$ 15,433

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 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, 2025 or the year ended December 31, 2024. 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 impaired. 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. The factors used to determine future cash flows associated with those properties include estimates of proved reserves, future commodity prices, timing of future production, operating costs, future capital expenditures, and, with respect to estimating fair value, a risk-adjusted discount rate.

The Partnership's estimates of fair value are determined at discrete points in time based on relevant market data. These estimates involve uncertainty, and cannot be determined with precision. There were no assets measured at fair value on a non-recurring basis for the six months ended June 30, 2025 or the year ended December 31, 2024.

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 and terminates on October 31, 2027. 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 2024, November 2024, and April 2025 borrowing base redeterminations reaffirmed the borrowing base at $580.0 million. After each redetermination we elected to maintain cash commitments at $375.0 million. The next semi-annual redetermination is scheduled for October 2025.

The Partnership’s borrowings under the Credit Facility bear interest at a floating rate determined by the type of loan the Partnership has elected to take: a secured overnight financing rate ("SOFR") loan or a base-rate loan. Both types of loans bear interest at a reference rate plus a margin that varies with the amount of borrowings outstanding under the Credit Facility. The reference rate for SOFR loans is equal to SOFR as published by the Federal Reserve Bank of New York, adjusted for the borrowing term, plus 0.10%, which is referred to as Adjusted Term SOFR. The reference rate for base rate loans is the highest of (a) Wells Fargo’s prime commercial lending rate for that day, (b) the Federal Funds Rate in effect on that day plus 0.50%, and (c) the Adjusted Term SOFR for a one-month tenor, plus 1.00%. As of December 31, 2024 and June 30, 2025, the applicable margin for the base rate loans ranged from 1.50% to 2.50%, and the margin for SOFR loans ranged from 2.50% to 3.50%.

The Partnership is 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.

The weighted-average interest rate of the Credit Facility was 7.10% during the six months ended June 30, 2025 and 7.50% for the twelve months ended December 31, 2024. 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. 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, 2025, the Partnership was in compliance with all financial covenants in the Credit Facility.

The aggregate principal balance outstanding was $99.0 million and $25.0 million at June 30, 2025 and December 31, 2024, respectively. The unused portion of the available borrowings under the Credit Facility was $276.0 million and $350.0 million at June 30, 2025 and December 31, 2024, 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 material to the unaudited interim 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, 2025 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,	
	2025	2024	2025	2024
	(in thousands)			
Cash—short and long-term incentive plans	$ 1,235	$ 1,125	$ 2,521	$ 2,385
Equity-based compensation—restricted common units	1,172	965	2,135	1,961
Equity-based compensation—restricted performance units	238	691	1,780	1,429
Board of Directors incentive plan	550	549	1,100	1,198
Total incentive compensation expense	$ 3,195	$ 3,330	$ 7,536	$ 6,973

For the six months ended June 30, 2025, the Partnership repurchased 256,771 common units at a weighted average price of $14.62 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 units to cover the employee's tax liability.

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 $20.39 per Series B cumulative convertible preferred unit, resulting in total proceeds of approximately $300.0 million.

The Series B cumulative convertible preferred units were initially entitled to quarterly distributions in an amount equal to 7.0% of the face amount of the preferred units per annum (the "Distribution Rate"). On November 28, 2023, the Distribution Rate was adjusted to 9.8% and will be readjusted every two years thereafter (each, a "Readjustment Date"). The rate set on each Readjustment Date is equal to 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 Partnership cannot pay any distributions on any junior securities, including common units, prior to paying the quarterly distribution payable to the preferred units, including any previously accrued and unpaid distributions.

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 $20.39, 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 during biennial 90-day windows. The next redemption window opens on November 28, 2025. The Partnership must provide 20 business days' notice to the holders of the Series B cumulative convertible preferred units of its intent to redeem, and the holders may either allow the redemption to occur or elect to convert the Series B cumulative convertible preferred units into common units as described above.

The Series B cumulative convertible preferred units had a carrying value of $300.5 million, including accrued distributions of $7.4 million, as of June 30, 2025 and December 31, 2024. 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,	
	2025	2024	2025	2024
	(in thousands, except per unit amounts)			
NET INCOME	$ 120,028	$ 68,322	$ 135,976	$ 132,249
Distributions on Series B cumulative convertible preferred units	(7,367)	(7,366)	(14,733)	(14,733)
NET INCOME ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON UNITS	$ 112,661	$ 60,956	$ 121,243	$ 117,516
ALLOCATION OF NET INCOME:				
General partner interest	$ —	$ —	$ —	$ —
Common units	112,661	60,956	121,243	117,516
	$ 112,661	$ 60,956	$ 121,243	$ 117,516
NUMERATOR:				
Numerator for basic EPU - Net income (loss) attributable to common unitholders	$ 112,661	$ 60,956	$ 121,243	$ 117,516
Effect of dilutive securities	7,367	—	—	—
Numerator for diluted EPU - Net income (loss) attributable to common unitholders after the effect of dilutive securities	$ 120,028	$ 60,956	$ 121,243	$ 117,516
DENOMINATOR:				
Denominator for basic EPU - weighted average common units outstanding (basic)	211,689	210,703	211,472	210,679
Effect of dilutive securities	15,072	—	—	—
Denominator for diluted EPU - weighted average number of common units outstanding after the effect of dilutive securities	226,761	210,703	211,472	210,679
NET INCOME ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON UNIT:				
Per common unit (basic)	$ 0.53	$ 0.29	$ 0.57	$ 0.56
Per common unit (diluted)	$ 0.53	$ 0.29	$ 0.57	$ 0.56

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,	
	2025	2024	2025	2024
	(in thousands)			
Potentially dilutive securities (common units):				
Series B cumulative convertible preferred units on an as-converted basis	—	15,072	15,072	15,072

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 of directors of the Partnership's general partner (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 beginning on November 28, 2023 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 9.8% of the face amount of the preferred units per annum, subject to readjustment every two years thereafter; 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,	
	2025	2024	2025	2024
Distributions declared and paid per common unit	$ 0.3750	$ 0.3750	$ 0.7500	$ 0.8500

Common Unit Repurchase Program

On October 30, 2023, the Board authorized a $150.0 million unit repurchase program. The unit repurchase program authorizes the Partnership to make repurchases on a discretionary basis as determined by management, subject to market condition, applicable legal requirements, available liquidity, and other appropriate factors. The Partnership made no repurchases under this program for the six months ended June 30, 2025. The program is funded from the Partnership’s cash on hand or through borrowings under the Credit Facility. Any repurchased units are canceled.

NOTE 12 - SUBSEQUENT EVENTS

Distribution

On July 16, 2025, the Board approved a distribution for the three months ended June 30, 2025 of $0.30 per common unit. Distributions will be payable on August 14, 2025 to unitholders of record at the close of business on August 7, 2025.

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 condensed 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, 2024 ("2024 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 Haynesville 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;

- domestic and foreign trade policies, including tariffs and other controls on imports or exports of goods, including energy products;
- 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 2024 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. We maximize value through marketing our mineral assets for lease and creatively structuring the terms on those leases to encourage and accelerate drilling activity. 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. Alongside our primary focus on traditional revenue streams from our asset base, we will continue to explore the relevance of our assets in energy transition, including opportunities in renewable energy and carbon sequestration.

As of June 30, 2025, 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 approximately 71,000 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

Development Activity

At the end of the second quarter, Aethon Energy ("Aethon") was operating two rigs on our Angelina, Nacogdoches, and San Augustine acreage in the Shelby Trough. During the quarter, Aethon successfully turned to sales 2 gross (0.10 net) wells. Aethon’s development program remains on track with the development agreements, with a total of 22 wells spud in the previous program years that ended in the second quarter of 2025. Of these wells, 7 gross (0.42 net) have turned to sales and 15 gross (0.93 net) are expected to turn to sales during the remainder of 2025 and early 2026. EXCO Resources Inc. also remains active on our acreage, completing 2 gross (0.08 net) wells in early June, and recently spud 2 gross (0.08 net) wells in July.

In the Louisiana Haynesville, development continued under our Accelerated Drilling Agreements (“ADAs”). These agreements incentivize operators to accelerate development in our high-interest areas in exchange for a modest reduction in royalty burden, allowing us to capture near-term revenue and reduce uncertainty about where the locations sit in the operator's development plan. During the second quarter, 3 gross (0.09 net) wells in De Soto and Sabine Parishes were turned to sales under our ADAs. This brings the total well count under the ADA program to seven. We expect another 2 gross (0.13 net) wells to be turned to sales during the third quarter of 2025.

In the Permian Basin, we continue to monitor activity including a large-scale development. A large operator has planned more than 34 gross (1.20 net) wells in Culberson County, Texas. To date, 30 of these wells have been spud. We anticipate 22 gross wells to turn to sales in the second half of 2025, with the remainder expected in the first half of 2026.

Revenant Joint Exploration Agreement and Farmout

In May 2025, we entered into a joint exploration agreement ("JEA") with Revenant Energy ("Revenant") covering approximately 270,000 gross acres across San Augustine, Nacogdoches, Angelina, Houston, and Trinity counties. The agreement includes annual well commitments that escalate over five years, from a minimum of 6 wells per year starting in 2026 increasing to a minimum of 25 wells per year for years 2030, and beyond, and require test wells in certain areas in order to continue operating across the full acreage. The agreement allows for non-operated working interest participation, and in June 2025, we entered into a farmout agreement with an external capital provider covering all of our undivided 35% working interest. For more information, see "—Liquidity and Capital Resources—Shelby Trough Development Agreements."

Amendment to Aethon Joint Exploration Agreements

In May 2025, we entered into an amendment to the JEAs with Aethon in Angelina and San Augustine counties which reduces the contract area to approximately 210,000 gross acres. Under the terms of the amendment, Aethon released over 50,000 gross acres from the contract area, in exchange for reducing the annual well commitment to a total of 16 wells across both JEAs. The farmout agreements covering non-operated working interests under these JEAs have terminated, and Aethon is absorbing that working interest as part of the amendment. For more information, see "—Liquidity and Capital Resources—Shelby Trough Development Agreements."

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.

Oil prices decreased in the first half of 2025 compared to the same period in 2024, primarily due to weakening global demand amid, changes in trade policies, including imposition of tariffs and other import/export restrictions, and escalating trade tensions between the United States and China. The decline was further driven by an oversupplied market, as OPEC+ members unwound voluntary production cuts and non-OPEC+ producers increased output. Natural gas prices increased during the first half of 2025 relative to the prior-year period. Prices were supported by unusually cold weather in the first quarter of 2025, which drove higher heating demand and resulted in lower-than-average storage levels. Natural gas pricing was also supported by higher wholesale power pricing this summer compared to last summer.

Given the dynamic nature of these events, including uncertainty regarding changes in trade policies and their resulting consequences, we cannot reasonably estimate how long 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:

	2025		2024	
Benchmark Prices[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
WTI spot oil price ($/Bbl)	$ 66.30	$ 71.87	$ 82.83	$ 83.96
Henry Hub spot natural gas ($/MMBtu)	3.26	4.11	2.42	1.54

[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:

	2025		2024	
U.S. Rotary Rig Count[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
Oil	432	484	479	506
Natural gas	109	103	97	112
Other	6	5	5	3
Total	547	592	581	621

[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 U.S. Energy Information Administration ("EIA") expects inventories will rise to 3.9 Tcf by the end of October 2025, which would be 3% higher than the five-year average.

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

	2025		2024	
Region[1]	**Second Quarter**	**First Quarter**	**Second Quarter**	**First Quarter**
East	602	284	660	363
Midwest	688	364	779	510
Mountain	228	165	239	162
Pacific	287	202	282	227
South Central	1,148	758	1,174	996
Total	2,953	1,773	3,134	2,258

[1] Source: EIA

Natural Gas Exports

Net natural gas exports averaged 14.2 Bcf per day during the first half of 2025, a 19% increase from the 2024 average. The EIA forecasts average exports of 15.1 Bcf per day for the remainder of 2025 and 16.0 Bcf per day for 2026. The EIA forecast reflects assumptions that U.S. LNG exports will increase as new LNG export projects begin operations during 2025 and 2026.

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, 2025 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, using swaps and collars with a term of no more than four years, up to 90% of our expected future volumes for the first 24 months, 70% for months 25 through 36, and 50% for months 37 through 48. As of June 30, 2025, we have hedged a portion of our expected future volumes for the remainder of 2025 and 2026.

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,	
	2025	2024	2025	2024
	(in thousands)			
Net income (loss)	$ 120,028	$ 68,322	$ 135,976	$ 132,249
Adjustments to reconcile to Adjusted EBITDA:				
Depreciation, depletion, and amortization	9,187	11,356	18,317	22,995
Interest expense	2,270	626	3,667	1,255
Income tax expense (benefit)	8	51	(77)	186
Accretion of asset retirement obligations	337	321	669	638
Equity–based compensation	1,960	2,205	5,015	4,588
Unrealized (gain) loss on commodity derivative instruments	(49,639)	17,366	2,751	42,453
Adjusted EBITDA	84,151	100,247	166,318	204,364
Adjustments to reconcile to Distributable cash flow:				
Change in deferred revenue	(1)	(1)	(2)	(2)
Cash interest expense	(1,994)	(358)	(3,117)	(719)
Preferred unit distributions	(7,367)	(7,366)	(14,733)	(14,733)
Distributable cash flow	$ 74,789	$ 92,522	$ 148,466	$ 188,910

Results of Operations

Three Months Ended June 30, 2025 Compared to Three Months Ended June 30, 2024

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

	Three Months Ended June 30,			
	2025	2024	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	863	953	(90)	(9.4)%
Natural gas (MMcf)[1]	13,710	16,350	(2,640)	(16.1)%
Equivalents (MBoe)	3,148	3,678	(530)	(14.4)%
Equivalents/day (MBoe)	34.6	40.4	(5.8)	(14.4)%
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 64.67	$ 77.53	$ (12.86)	(16.6)%
Natural gas ($/Mcf)[1]	3.37	2.23	1.14	51.1 %
Equivalents ($/Boe)	$ 32.40	$ 30.01	$ 2.39	8.0 %
Revenue:				
Oil and condensate sales	$ 55,807	$ 73,889	$ (18,082)	(24.5)%
Natural gas and natural gas liquids sales[1]	46,189	36,493	9,696	26.6 %
Lease bonus and other income	4,714	4,789	(75)	(1.6)%
Revenue from contracts with customers	106,710	115,171	(8,461)	(7.3)%
Gain (loss) on commodity derivative instruments	52,784	(5,547)	58,331	NM[2]
Total revenue	$ 159,494	$ 109,624	$ 49,870	45.5 %
Operating expenses:				
Lease operating expense	$ 2,990	$ 2,579	$ 411	15.9 %
Production costs and ad valorem taxes	9,026	13,469	(4,443)	(33.0)%
Exploration expense	1,749	14	1,735	NM[2]
Depreciation, depletion, and amortization	9,187	11,356	(2,169)	(19.1)%
General and administrative	13,924	13,395	529	3.9 %
Other expense:				
Interest expense	2,270	626	1,644	262.6 %

[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.

[2] Not meaningful.

Revenue

Total revenue for the quarter ended June 30, 2025 increased compared to the quarter ended June 30, 2024. The increase in total revenue in the second quarter of 2025 is primarily due to a gain on our commodity derivative instruments compared to a loss in the corresponding prior period and an increase in natural gas and NGL sales, which were partially offset by a decrease in oil and condensate sales.

Oil and condensate sales. Oil and condensate sales decreased for the quarter ended June 30, 2025 as compared to the corresponding period in 2024 primarily due to lower production volumes and realized commodity prices. The decrease in oil and condensate production was driven by reduced mineral and royalty volumes in the Permian Basin. Our mineral and royalty interest oil and condensate volumes accounted for 96% and 95% of total oil and condensate volumes for quarters ended June 30, 2025 and 2024, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales increased for the quarter ended June 30, 2025 as compared to the corresponding prior period. The increase was due to higher realized commodity prices between the comparative periods partially offset by a decrease in production volumes. The decrease in production was driven by reduced royalty interest volumes, primarily within the Haynesville/Bossier play. Mineral and royalty interest production accounted for 96% and 94% of our natural gas volumes for the quarters ended June 30, 2025 and 2024, respectively.

Gain (loss) on commodity derivative instruments. 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. During the second quarter of 2025, we recognized a gain from our commodity derivative instruments compared to a loss in the same period in 2024. For the three months ended June 30, 2025, we recognized $3.2 million of realized gains and $49.6 million of unrealized gains from our oil and natural gas commodity contracts, compared to $11.8 million of realized gains and $17.4 million of unrealized losses in the same period in 2024. The unrealized gains on our commodity contracts during the second quarter of 2025 were primarily driven by changes in the forward commodity price curves for oil. The unrealized losses for the same period in 2024 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 2025 was consistent with the same period in 2024. Leasing activity in the Permian Basin and Bakken/Three Forks plays made up the majority of lease bonus and other income for the second quarter of 2025, while the majority of the second quarter 2024 activity came from leasing activity in the Permian Basin.

<u>Operating Expenses</u>

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 increased for the quarter ended June 30, 2025 as compared to the same period in 2024, primarily due to increased 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, 2025, production costs and ad valorem taxes decreased as compared to the quarter ended June 30, 2024, primarily due to lower production taxes from decreased oil commodity prices and reduced oil and natural gas production volumes, as well as lower ad valorem tax estimates.

Exploration expense. Exploration expense typically consists of dry-hole expenses, payments for delay rentals where the Partnership is the lessee, and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. For the quarter ended June 30, 2025, exploration expenses increased compared to the same period in 2024, primarily due to additional costs related to seismic data acquisition projects associated with existing and future development programs in the expanded Shelby Trough area. Exploration expenses were minimal in the second quarter of 2024.

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, 2025 as compared to the same period in 2024 due to lower production volumes.

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, 2025, general and administrative expenses slightly increased as compared to the same period in 2024, primarily due to higher cash compensation driven by increased salaries and certain one-time personnel-related costs.

Interest expense. Interest expense increased for the quarter ended June 30, 2025 as compared to the corresponding period in 2024. The increase was due to higher average outstanding borrowings under our Credit Facility.

Six Months Ended June 30, 2025 Compared to Six Months Ended June 30, 2024

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

	Six Months Ended June 30,			
	2025	2024	Variance	
	(Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)	1,579	1,876	(297)	(15.8)%
Natural gas (MMcf)[1]	28,563	32,820	(4,257)	(13.0)%
Equivalents (MBoe)	6,340	7,346	(1,006)	(13.7)%
Equivalents/day (MBoe)	35.0	40.4	(5.4)	(13.4)%
Realized prices, without derivatives:				
Oil and condensate ($/Bbl)	$ 67.07	$ 77.35	$ (10.28)	(13.3)%
Natural gas ($/Mcf)[1]	3.66	2.39	1.27	53.1 %
Equivalents ($/Boe)	$ 33.17	$ 30.44	$ 2.73	9.0 %
Revenue:				
Oil and condensate sales	$ 105,900	$ 145,113	$ (39,213)	(27.0)%
Natural gas and natural gas liquids sales[1]	104,424	78,504	25,920	33.0 %
Lease bonus and other income	11,639	8,337	3,302	39.6 %
Revenue from contracts with customers	221,963	231,954	(9,991)	(4.3)%
Gain (loss) on commodity derivative instruments	(3,217)	(16,837)	13,620	80.9 %
Total revenue	$ 218,746	$ 215,117	$ 3,629	1.7 %
Operating expenses:				
Lease operating expense	$ 5,152	$ 5,011	$ 141	2.8 %
Production costs and ad valorem taxes	19,211	26,507	(7,296)	(27.5)%
Exploration expense	6,859	17	6,842	NM[2]
Depreciation, depletion, and amortization	18,317	22,995	(4,678)	(20.3)%
General and administrative	29,096	27,485	1,611	5.9 %
Other expense:				
Interest expense	3,667	1,255	2,412	192.2 %

[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, 2025 increased compared to the corresponding prior period. The increase in total revenue is primarily due to a gain in natural gas and NGL sales and a reduced loss on our commodity derivative instruments compared to the corresponding prior period, which were partially offset by an decrease in oil and condensate sales.

Oil and condensate sales. Oil and condensate sales during the six months ended June 30, 2025 decreased compared to the corresponding prior period primarily due to lower production volumes and realized commodity prices. The decrease in oil and condensate production was driven by reduced mineral and royalty production in the Permian Basin. Our mineral and royalty interest oil and condensate volumes accounted for 96% and 94% of total oil and condensate volumes for the six months ended June 30, 2025 and 2024, respectively.

Natural gas and natural gas liquids sales. Natural gas and NGL sales during the six months ended June 30, 2025 increased compared to the corresponding prior period due to higher realized commodity prices partially offset by lower production volumes. The decrease in production volumes was driven by a reduction in royalty interest production volumes, primarily within the Haynesville/Bossier play. Mineral and royalty interest production accounted for 96% and 95% of our natural gas volumes for the six months ended June 30, 2025 and 2024, respectively.

Gain (loss) on commodity derivative instruments. During the six months ended June 30, 2025, we recognized a reduced loss from our commodity derivative instruments compared to the corresponding period in 2024. In the six months ended June 30, 2025, we recognized $0.5 million of realized losses and $2.7 million of unrealized losses from our oil and natural gas commodity contracts, compared to $25.6 million of realized gains and $42.5 million of unrealized losses in the same period in 2024. Unrealized losses on our commodity contracts during the six months ended June 30, 2025 were primarily driven by changes in forward natural gas price curves, compared to the corresponding period in 2024 when unrealized losses were driven by changes in forward oil and natural gas price curves.

Lease bonus and other income. Lease bonus and other income for the six months ended June 30, 2025 was higher than the same period in 2024. Leasing activity in the Permian Basin and proceeds from the surface use waivers on our mineral acreage supporting solar development in Louisiana made up the majority of lease bonus and other income for the six months ended June 30, 2025, while a substantial portion of the activity in the corresponding period in 2024 came from leasing activity in the Permian Basin and the Austin Chalk play trend and proceeds from surface use waivers on our mineral acreage supporting solar development in Texas.

Operating and Other Expenses

Lease operating expense. Lease operating expense slightly increased for the six months ended June 30, 2025 as compared to the same period in 2024, primarily due to increased nonrecurring service-related expenses, including workovers.

Production costs and ad valorem taxes. For the six months ended June 30, 2025, production costs and ad valorem taxes decreased as compared to the six months ended June 30, 2024, primarily due to lower production taxes from decreased oil commodity prices and reduced oil and natural gas production volumes, as well as lower ad valorem tax estimates.

Exploration expense. For the six months ended June 30, 2025, exploration expense increased as compared to the six months ended June 30, 2024, primarily due to a one-time $4.0 million purchase of seismic data and additional costs related to seismic data acquisition projects.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization decreased for the six months ended June 30, 2025 as compared to the same period in 2024, primarily due to decreased production volumes.

General and administrative. For the six months ended June 30, 2025, general and administrative expenses increased as compared to the same period in 2024, primarily due to increased cash and equity-based compensation. The increase in cash compensation was driven by increased salaries and certain one-time personnel-related costs. The increase in equity-based compensation was primarily due to a lower level of equity award forfeitures for the six months ended June 30, 2025 as compared to the same period in 2024.

Interest expense. Interest expense increased for the six months ended June 30, 2025 as compared to the corresponding period in 2024. The increase was due to higher average outstanding borrowings under our Credit Facility.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations and borrowings under our Credit Facility. Our primary uses of cash are for distributions to our unitholders, reducing outstanding borrowings under our Credit Facility, and for investing in our business. On November 28, 2023 the distribution rate for the Series B cumulative convertible preferred units was adjusted to 9.8% and will be readjusted every two years thereafter (each, a "Readjustment Date"). The rate set on each Readjustment Date is equal to 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. We have 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 each Readjustment Date at a redemption price of $20.39 per Series B cumulative convertible preferred unit, which is equal to par value. Depending on market conditions among other factors, we may use funds from the future issuance of common units or other equity securities or debt to redeem some or all of the preferred units. See "Note 9 - Preferred Units" 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, and proceeds from any future issuances of equity and debt. 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.

On October 30, 2023, the Board authorized a $150.0 million unit repurchase program which authorizes us to make repurchases on a discretionary basis. The program will be funded from our cash on hand or through borrowings under the Credit Facility. Any repurchased units will be cancelled. See "Note 11 – Common Units" to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Cash Flows

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

	Six Months Ended June 30,		
	2025	**2024**	**Change**
	(in thousands)		
Cash flows provided by operating activities	$ 145,311	$ 204,845	$ (59,534)
Cash flows used in investing activities	(42,687)	(51,681)	8,994
Cash flows used in financing activities	(102,624)	(196,777)	94,153

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 decreased for the six months ended June 30, 2025 as compared to the same period of 2024. The decrease was primarily due to reduced oil sales due to lower realized commodity prices and production, lower amounts of cash received from the settlement of commodity derivatives, and changes in operating assets and liabilities due to the timing of payments. The overall decrease was partially offset by higher natural gas and NGL sales in the six months ended June 30, 2025 compared to the same period of 2024.

Investing Activities. Net cash used in investing activities in the six months ended June 30, 2025 decreased as compared to the same period of 2024. The decrease was primarily due to reduced acquisitions of oil and natural gas properties in the six months ended June 30, 2025 compared to the same period of 2024.

Financing Activities. Cash flows used in financing activities decreased for the six months ended June 30, 2025 as compared to the same period of 2024. The decrease was primarily driven by lower distributions paid to unitholders and by net borrowings on our Credit Facility for the six months ended June 30, 2025, compared to no net borrowings for the six months ended June 30, 2024.

Development Capital Expenditures

Our 2025 capital expenditure budget associated with our non-operated working interests is expected to be approximately $2.3 million, net of farmout reimbursements, of which $0.3 million has been invested in the six months ended June 30, 2025. The majority of this capital is anticipated to be spent on workovers and recompletions on existing wells in which we own a working interest. Through June 30, 2025, we have also spent $4.6 million acquiring leases in areas around our drilling programs.

Acquisitions

During the six months ended June 30, 2025, we acquired mineral and royalty interests that consisted of primarily unproved oil and natural gas properties from various sellers for an aggregate of $45.4 million, including capitalized direct transaction costs. The consideration paid consisted of $38.0 million in cash that was funded from operating activities and $7.4 million in equity that was funded through the issuance of common units of the Partnership based on the fair values of the common units issued on the acquisition dates. These acquisitions were considered asset acquisitions and were primarily located in the Gulf Coast land region. Our current commercial strategy includes the continuation of meaningful, targeted mineral and royalty acquisitions to complement our existing positions.

See "Note 3 – Oil and Natural Gas Properties" to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Shelby Trough Development Agreements

We are party to a series of JEAs with unaffiliated operators covering portions of our undeveloped leasehold and mineral acreage in the Shelby Trough area of East Texas. These agreements grant the operator exclusive rights to develop designated acreage in exchange for meeting minimum annual drilling commitments. Each JEA also includes a banked well provision, which allows operators that exceed their annual drilling commitments to carry forward excess wells to satisfy future obligations, subject to defined caps. Wells drilled are typically required to turn to sales within 260 days of rig release. The agreements are structured to generate value from our undeveloped acreage while limiting our exposure to capital and operational costs.

Aethon Joint Exploration Agreements

We have two JEAs with Aethon covering portions of our acreage in San Augustine and Angelina counties, Texas. In May 2025, the parties entered into a letter agreement amending the JEAs. As amended, the agreements provide for a combined annual minimum drilling commitment of 16 wells across both contract areas.

Aethon drilled a combined 22 wells under the two JEAs during the program years that ended in the second quarter of 2025. One well has been scheduled for plugging and will be replaced. As of June 30, 2025, 15 of those wells had not yet turned to sales and are expected to begin production during the remainder of 2025 and early 2026. Aethon expects to drill 15 wells in the next program year that begins in July 2025 and apply one of its 11 banked wells toward its commitment.

Revenant Joint Exploration Agreement

In May 2025, we entered into a JEA with Revenant covering an expanded portion of our Shelby Trough acreage, primarily located in Angelina, Nacogdoches, and San Augustine counties in Texas. The agreement grants Revenant exclusive development rights across three designated areas of interest ("AOIs") and requires annual well commitments, including test wells in certain areas, to maintain development rights across the full contract area. The agreement allows for non-operated working interest participation, and in June 2025 we entered into a farmout agreement with an external capital provider covering all of our undivided 35% working interest.

The well commitments under the agreement escalate over a five-year period, with the following table summarizing the well commitments across the three AOIs:

Program Year	Calendar Year	AOI 1	AOI 2	AOI 3	Total Wells
1	2026	6	—	—	6
2	2027	8	—	—	8
3	2028	10	1	—	11
4	2029	12	2	2	16
5 and thereafter	2030 and beyond	15	5	5	25

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 and terminates on October 31, 2027. 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 April and October. The April 2024, November 2024, and April 2025 borrowing base redeterminations reaffirmed the borrowing base at $580.0 million. After each redetermination we elected to maintain cash commitments at $375.0 million. The next semi-annual redetermination is scheduled for October 2025.

We are subject to various affirmative, negative, and financial maintenance covenants which pose limitations on future borrowings, leases, hedging, and sales of assets. As of June 30, 2025, we were in compliance with all debt covenants.

See "Note 6 – Credit Facility" to the unaudited interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Contractual Obligations

As of June 30, 2025, there have been no material changes to our contractual obligations previously disclosed in our 2024 Annual Report on Form 10-K.

Critical Accounting Policies and Related Estimates

As of June 30, 2025, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2024 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 financial 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 the difference between the fixed contract price and the market settlement price. The market settlement 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 applied a 10% discount to the SEC commodity pricing for the three months ended June 30, 2025. Applying this discount results in an approximate 1.3% reduction of proved reserve volumes as compared to the undiscounted June 30, 2025 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, 2025, we had seven counterparties, all of which were rated Baa2 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, 2025, we had $71.6 million weighted average outstanding borrowings under our Credit Facility, bearing interest at a weighted average interest rate of 7.10%. 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 $0.4 million for the six months ended June 30, 2025, 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, 2025 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, 2025 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 2024 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 2024 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

During the three months ended June 30, 2025, we closed on purchases of certain mineral and royalty interests using an aggregate of 253,158 common units valued at $3.5 million to fund the purchases.

The issuance of the common units was made in reliance upon an exemption from the registration requirements of the Securities Act of 1933, as amended, pursuant to Section 4(a)(2) thereunder.

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table sets forth our purchases of our common units during the three months ended June 30, 2025:

Purchases of Common Units

Period	Total Number of Common Units Purchased[1]	Average Price Paid Per Unit	Total Number of Common Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Common Units That May Yet Be Purchased Under the Plans or Programs[2]
June 1 - June 30, 2025	35,721	$ 13.05	—	$ 150,000,000

[1] Consists of units withheld to satisfy tax withholding obligations upon the vesting of certain long-term incentive equity awards held by our executive officers and certain other employees.

[2] On October 30, 2023, the Board authorized the repurchase of up to $150.0 million in common units. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be repurchased when we might otherwise be precluded from doing so under insider trading laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion.

Item 5. Other Information

During the three months ended June 30, 2025, 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)).
10.1^	Black Stone Minerals, L.P. 2025 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P. Current Report on Form 8-K filed on June 18, 2025 (SEC File No. 001-37362)).
10.2^	Separation Agreement and General Release of Claims, dated as of June 29, 2025, by and among Carrie Clark, Black Stone Natural Resources Management Company, and Black Stone Minerals GP, L.L.C. (incorporated herein by reference to Exhibit 10.1 of Black Stone Minerals, L.P. Current Report on Form 8-K filed on June 30, 2025 (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.
^ Management contract or compensatory plan or arrangement.

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 5, 2025	By:	/s/ Thomas L. Carter, Jr.
		Thomas L. Carter, Jr. President, Chief Executive Officer, and Chairman (Principal Executive Officer)
Date: August 5, 2025	By:	/s/ H. Taylor DeWalch
		H. Taylor DeWalch Senior Vice President, 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 5, 2025

/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, H. Taylor DeWalch, 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 5, 2025

/s/ H. Taylor DeWalch

H. Taylor DeWalch
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 H. Taylor DeWalch, 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 5, 2025

/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 5, 2025

/s/ H. Taylor DeWalch

H. Taylor DeWalch
Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.