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

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended March 31, 2015

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

(713) 658-0647
(Registrant's telephone number, including area code)

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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☑ (Do not check if a smaller reporting company)	Smaller reporting company	☐

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

As of May 29, 2015, there were 96,177,147 common limited partner units, 95,057,312 subordinated limited partner units, and 117,963 preferred units of the registrant outstanding.

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

BLACK STONE MINERALS, L.P. PREDECESSOR
CONSOLIDATED BALANCE SHEETS
(In thousands)

	March 31, 2015 (Unaudited)	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 8,368	$ 14,803
Accounts receivable	50,794	74,092
Commodity derivative assets	38,913	37,471
Prepaid expenses and other current assets	10,523	8,538
TOTAL CURRENT ASSETS	108,598	134,904
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, on the basis of the successful efforts method of accounting, includes unproved properties of $625,392 and $626,376 at March 31, 2015 and December 31, 2014, respectively	2,394,096	2,379,543
Accumulated depreciation, depletion and amortization, including impairment	(1,232,584)	(1,191,861)
Oil and natural gas properties, net	1,161,512	1,187,682
Other property and equipment, net of accumulated depreciation of $13,558 and $12,994 at March 31, 2015 and December 31, 2014, respectively	1,098	1,664
NET PROPERTY AND EQUIPMENT	1,162,610	1,189,346
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	3,083	2,532
TOTAL ASSETS	$ 1,274,291	$ 1,326,782
LIABILITIES, MEZZANINE EQUITY AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 31,080	$ 29,415
Accrued liabilities	12,165	16,252
Accrued partners' distribution payable	52,724	52,905
TOTAL CURRENT LIABILITIES	95,969	98,572
LONG-TERM LIABILITIES		
Credit facilities	389,000	394,000
Accrued incentive compensation	3,714	6,530
Commodity derivative liabilities	37	—
Deferred revenue	3,813	3,917
Asset retirement obligations	9,621	9,381
TOTAL LIABILITIES	502,154	512,400
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity - redeemable preferred units, 118 and 157 units outstanding at March 31, 2015 and December 31, 2014, respectively	120,889	161,165
EQUITY		
Partners' equity - general partner units	—	—
Partners' equity - common limited partner units, 167,767 and 164,484 units outstanding at March 31, 2015 and December 31, 2014, respectively	648,672	650,598
Noncontrolling interests	2,576	2,619
TOTAL EQUITY	651,248	653,217
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 1,274,291	$ 1,326,782

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

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

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
REVENUE		
Oil and condensate sales	$ 36,163	$ 59,642
Natural gas and natural gas liquids sales	31,640	58,206
Gain (loss) on commodity derivative instruments	19,647	(5,995)
Lease bonus and other income	3,611	15,559
TOTAL REVENUE	91,061	127,412
OPERATING (INCOME) EXPENSE		
Lease operating expenses and other	6,172	4,869
Production costs and ad valorem taxes	8,256	10,586
Depreciation, depletion and amortization	27,891	23,134
Impairment of oil and natural gas properties	13,467	—
General and administrative	14,818	15,451
Accretion of asset retirement obligations	271	147
Gain on sale of assets	(7)	—
TOTAL OPERATING EXPENSE	70,868	54,187
INCOME FROM OPERATIONS	20,193	73,225
OTHER INCOME (EXPENSE)		
Interest and investment income	1	22
Interest expense	(2,945)	(3,433)
Other income	50	70
TOTAL OTHER EXPENSE	(2,894)	(3,341)
NET INCOME	17,299	69,884
NET (INCOME) LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(9)	3
DIVIDENDS ON PREFERRED UNITS	(2,909)	(3,882)
NET INCOME ATTRIBUTABLE TO THE GENERAL PARTNER AND LIMITED PARTNERS	14,381	66,005
ALLOCATION OF NET INCOME ATTRIBUTABLE TO:		
General partner interest	—	—
Common limited partner interest	14,381	66,005
	$ 14,381	$ 66,005
NET INCOME ATTRIBUTABLE TO LIMITED PARTNERS PER UNIT:		
Per common limited partner unit (basic and diluted)	$ 0.09	$ 0.40
Weighted average common limited partner units outstanding (basic and diluted)	167,452	164,585

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

BLACK STONE MINERALS, L.P. PREDECESSOR
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)
(In thousands)

	Class A and Class B common units	Partners' equity— common units	Noncontrolling interest	Total
BALANCE AT DECEMBER 31, 2014	164,484	$ 650,598	$ 2,619	$ 653,217
Conversion of redeemable preferred units	2,749	39,223	—	39,223
Restricted common units granted	562	—	—	—
Repurchases of common units	(28)	(523)	—	(523)
Equity-based compensation	—	1,243	—	1,243
Distributions	—	(56,250)	(52)	(56,302)
Net income	—	17,290	9	17,299
Dividends on preferred units	—	(2,909)	—	(2,909)
BALANCE AT MARCH 31, 2015	167,767	$ 648,672	$ 2,576	$ 651,248

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

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

	Three Months Ended March 31,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 17,299	$ 69,884
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	27,891	23,134
Impairment of oil and natural gas properties	13,467	—
Accretion of asset retirement obligations	271	147
Amortization of deferred charges	241	241
(Gain) loss on commodity derivative instruments	(19,647)	5,995
Net cash received (paid) on settlement of commodity derivative instruments	17,450	(2,084)
Equity-based compensation	1,243	3,499
Gain on disposal of assets	(7)	—
Changes in operating assets and liabilities:		
Accounts receivable	23,298	(16,882)
Prepaid expenses and other current assets	(365)	(333)
Accounts payable and accrued liabilities	(6,620)	(6,914)
Deferred revenue	(104)	(2,516)
Settlement of asset retirement obligations	(58)	(8)
NET CASH PROVIDED BY OPERATING ACTIVITIES	74,359	74,163
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to oil and natural gas properties	(13,612)	(13,966)
Purchase of other property and equipment	—	(60)
Proceeds from the sale of oil and natural gas properties	406	5,439
Acquisitions of oil and natural gas properties	—	(29,431)
NET CASH USED IN INVESTING ACTIVITIES	(13,206)	(38,018)
CASH FLOWS FROM FINANCING ACTIVITIES		
Distributions to common equity owners	(56,483)	(55,517)
Repurchase of common equity units	(523)	(406)
Dividends on preferred units	(3,962)	(3,968)
Net (repayments) borrowings under senior line of credit	(5,000)	11,500
Note receivable-officers	—	101
Payments incurred for initial public offering	(1,620)	—
NET CASH USED IN FINANCING ACTIVITIES	(67,588)	(48,290)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(6,435)	(12,145)
CASH AND CASH EQUIVALENTS - beginning of the period	14,803	30,123
CASH AND CASH EQUIVALENTS - end of the period	$ 8,368	$ 17,978
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 2,664	$ 3,187
NON-CASH ACTIVITIES		
Property additions financed through accounts payable and accrued liabilities	$ 15,512	$ 23,332
Liabilities assumed as consideration for oil and natural gas properties acquired	$ —	$ 7,000
Deferred revenue settled through acquisition of oil and natural gas properties	$ —	$ (2,657)
Asset retirement obligations incurred	$ 27	$ 31
Accrued distributions payable	$ (181)	$ 806
Conversion of redeemable preferred units	$ (39,223)	$ —

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

NOTE 1—BUSINESS AND BASIS OF PRESENTATION

Description of the business: Black Stone Minerals Company, L.P., a Delaware limited partnership, and its subsidiaries (collectively referred to as "BSMC" or the "Predecessor") own oil and natural gas mineral interests in the United States ("U.S."). Black Stone Minerals, L.P. ("BSM") is a publicly traded Delaware limited partnership formed on September 16, 2014. On May 6, 2015, BSM completed its initial public offering (the "IPO") of 22,500,000 common units representing limited partner interests at a price to the public of $19.00 per common unit. BSM received proceeds of $391.6 million from the sale of its common units, net of underwriting discount, structuring fee, and estimated offering expenses (including costs previously incurred and capitalized). BSM used the net proceeds from the IPO to repay substantially all indebtedness outstanding under its credit facility. On May 1, 2015, BSM's common units began trading on the New York Stock Exchange under the symbol "BSM."

In connection with the IPO, BSMC was merged into a wholly owned subsidiary of BSM, with BSMC as the surviving entity. Pursuant to the merger, the Class A and Class B common units representing limited partner interests of the Predecessor were converted into an aggregate of 72,574,715 common units and 95,057,312 subordinated units of BSM at a conversion ratio of 12.9465:1 for 0.4329 common units and 0.5671 subordinated units, and the preferred units of BSMC were converted into an aggregate of 117,963 preferred units of BSM at a conversion ratio of one to one. The merger is accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. Unless otherwise stated or the context otherwise indicates, all references to the "Company" or similar expressions for time periods prior to the IPO refer to Black Stone Minerals Company, L.P. and its subsidiaries, the Predecessor, for accounting purposes. For time periods subsequent to the IPO, these terms refer to Black Stone Minerals, L.P. and its subsidiaries.

In addition to mineral interests, the Company's assets include nonparticipating and overriding royalty interests. These non-cost-bearing interests are collectively referred to as "mineral and royalty interests." As of March 31, 2015, the Company's mineral and royalty interests are located in most of the major onshore oil and natural gas producing basins spread across 41 states and 62 onshore oil and natural gas producing basins of the continental U.S. The Company also owns non-operated working interests in certain oil and natural gas properties.

Basis of presentation: The accompanying unaudited interim consolidated financial statements of the Company have been prepared in accordance with generally accepted accounting principles ("GAAP") in the U.S. 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 U.S. GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Company's annual consolidated financial statements and related notes included in its final prospectus (the "Prospectus") dated April 30, 2015 and filed with the SEC, pursuant to Rule 424(b) under the Securities Act of 1933 (the "Securities Act"), on May 1, 2015. Certain reclassifications have been made to the prior periods presented to conform to the current period financial statement presentation. The reclassifications have no effect on the consolidated financial position, results of operations, or cash flows of the Company. In the opinion of management, all material adjustments, which are of a normal and recurring nature, necessary for a fair presentation of the results for the periods presented have been reflected. The results of operations for the three months ended March 31, 2015 are not necessarily indicative of the results to be expected for the full year.

The Company evaluates significant terms of its investments to determine the method of accounting applied to the investments. Investments in which the Company has less than a 20% ownership interest and does not have control or exercise significant influence are accounted for under the cost method. The Company's cost method investment is included in deferred charges and other long-term assets in the consolidated balance sheets. Investments in which the Company exercises control are consolidated, and the noncontrolling interests of such investments, which are not attributable directly or indirectly to the Company, are presented as a separate component of net income and equity in the accompanying consolidated financial statements.

The consolidated financial statements include undivided interests in oil and natural gas property rights. The Company 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 consolidated balance sheets, statements of operations, and cash flow statements.

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

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant accounting policies: Our significant accounting policies are disclosed in Note 2 of the consolidated financial statements for the years ended December 31, 2014 and 2013 included in the Prospectus. There have been no changes in such policies or the application of such policies during the quarter ended March 31, 2015.

New accounting pronouncements: In May 2014, the Financial Accounting Standards Board (the "FASB") issued an accounting standards update on a comprehensive new revenue recognition standard that will supersede Accounting Standards Codification ("ASC") 605, *Revenue Recognition*. The new accounting guidance creates a framework under which an entity will allocate the transaction price to separate performance obligations and recognize revenue when each performance obligation is satisfied. Under the new standard, entities will be required to use judgment and make estimates, including identifying performance obligations in a contract, estimating the amount of variable consideration to include in the transaction price, allocating the transaction price to each separate performance obligation and determining when an entity satisfies its performance obligations. The standard allows for either "full retrospective" adoption, meaning that the standard is applied to all of the periods presented with a cumulative catch-up as of the earliest period presented, or "modified retrospective" adoption, meaning the standard is applied only to the most current period presented in the financial statements with a cumulative catch-up as of the current period. The accounting standard will be effective for reporting periods beginning after December 15, 2016 for public companies. However, in April 2015, the FASB tentatively decided to defer the effective date by one year to be effective for annual reporting periods beginning after December 15, 2017. The Company is evaluating the impact that the new accounting guidance will have on its consolidated financial position, results of operations, and cash flows and has not yet determined the method by which it will adopt the standard.

In April 2015, the FASB issued an accounting standards update that requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying value of that debt liability, consistent with debt discounts. The guidance is effective retrospectively for fiscal years, and interim periods within those years, beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued. The Company does not expect the impact of adopting this guidance will be material to the Company's consolidated financial statements and related disclosures.

In April 2015, the FASB issued an accounting standards update that specifies that for purposes of calculating historical earnings per unit under the two-class method, the earnings (losses) of a transferred business before the date of a dropdown transaction should be allocated entirely to the general partner. In that circumstance, the previously reported earnings per unit of the limited partners (which is typically the earnings per unit measure presented in the financial statements) would not change as a result of the dropdown transaction. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the dropdown transaction occurs for purposes of computing earnings per unit under the two-class method also are required. The guidance is effective retrospectively for fiscal years, and interim periods within those years, beginning after December 15, 2015. Early adoption is permitted. The Company does not expect the impact of adopting this guidance will be material to the Company's consolidated financial statements and related disclosures.

NOTE 3—ASSET RETIREMENT OBLIGATIONS

The asset retirement obligation ("ARO") liability reflects the present value of estimated costs of dismantlement, removal, site reclamation, and similar activities associated with the Company's oil and natural gas properties. The Company utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Company estimates the ultimate productive life of its properties, a risk-adjusted discount rate, and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing ARO liability, a corresponding adjustment is made to the oil and natural gas property balance. The following table describes changes to the Company's ARO liability during the period:

	For the three months ended March 31, 2015 (In thousands)
Beginning asset retirement obligations	$ 9,381
Liabilities incurred	27
Liabilities settled	(58)
Accretion expense	271
Ending asset retirement obligations	$ 9,621

NOTE 4—DERIVATIVES AND FINANCIAL INSTRUMENTS

The Company's ongoing operations expose it to changes in the market price for oil and natural gas. To mitigate the given commodity price risk associated with its operations, the Company uses derivative instruments. From time to time, such instruments may include fixed-price contracts, variable to fixed-price swaps, costless collars, and other contractual arrangements. The Company does not enter into derivative instruments for speculative purposes.

Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. With a costless collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the exercise price of the purchased put. The Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the exercise price for the sold call of the collar. The settlement paid or received is the difference between the market price on the settlement date and the related exercise price. The Company has also entered into commodity derivative instruments in the form of fixed price swap contracts. A fixed price swap contract between the Company and a counterparty specifies a fixed commodity price and a future settlement date. The Company will receive from, or pay to, the counterparty the difference between the fixed swap price and the market price on the settlement date. All derivative instruments that have not yet been settled in cash are reflected as either assets or liabilities in the Company's accompanying consolidated balance sheets as of March 31, 2015 and December 31, 2014. See Note 5 – Fair Value Measurement for further discussion.

The table below summarizes the fair value and classification of the Company's derivative instruments:

As of March 31, 2015
(In thousands)

Classification	Balance Sheet Location	Gross Fair Value	Effect of Counterparty Netting	Net Carrying Value on Balance Sheet
Assets:				
Current asset	Commodity derivative assets	$ 39,055	$ (142)	$ 38,913
Non-current asset	Deferred charges and other long-term assets	992	(200)	792
Total assets		$ 40,047	$ (342)	$ 39,705
Liabilities:				
Current liability	Commodity derivative liabilities	$ 142	$ (142)	$ —
Non-current liability	Commodity derivative liabilities	237	(200)	37
Total liabilities		$ 379	$ (342)	$ 37

As of December 31, 2014
(In thousands)

Classification	Balance Sheet Location	Gross Fair Value	Effect of Counterparty Netting	Net Carrying Value on Balance Sheet
Assets:				
Current asset	Commodity derivative assets	$ 37,656	$ (185)	$ 37,471
Non-current asset	Deferred charges and other long-term assets	—	—	—
Total assets		$ 37,656	$ (185)	$ 37,471
Liabilities:				
Current liability	Commodity derivative liability	$ 185	$ (185)	$ —
Non-current liability	Commodity derivative liability	—	—	—
Total liabilities		$ 185	$ (185)	$ —

Changes in the fair values of the Company's derivative instruments (both assets and liabilities) are presented on a net basis in the accompanying consolidated statements of operations. Changes in the fair value of the Company's commodity derivative instruments (both assets and liabilities) are as follows:

Derivatives not designated as hedging instruments under ASC 815	For the three months ended March 31, 2015	2014
	(In thousands)	
Beginning fair value of commodity derivative instruments	$ 37,471	$ (1,812)
Gain (loss) on oil derivative instruments	13,019	(1,551)
Gain (loss) on natural gas derivative instruments	6,628	(4,444)
Net cash (received) paid on settlements of oil derivative instruments	(11,509)	18
Net cash (received) paid on settlements of natural gas derivative instruments	(5,941)	2,066
Net change in fair value of commodity derivative instruments	2,197	(3,911)
Ending fair value of commodity derivative instruments	$ 39,668	$ (5,723)

The Company had the following open derivative contracts for oil as of March 31, 2015:

Period and Type of Contract	Volume (Bbl)	Weighted Average (Per Bbl)	Range (Per Bbl) Low	High
Oil Collars:				
2015				
Collar contracts:				
Call Options	625,000	$ 102.02	$ 99.05	$ 104.00
Put Options	625,000	$ 84.88	$ 80.00	$ 90.00
Oil Swaps:				
2015				
Swap contracts:	1,106,000	$ 58.71	$ 52.05	$ 61.71
2016				
Swap contracts:	1,540,000	$ 57.98	$ 54.80	$ 60.41

The Company had the following open derivative contracts for natural gas as of March 31, 2015:

Period and Type of Contract	Volume (MMBtu)	Weighted Average (Per MMBtu)	Range (Per MMBtu) Low	High
Natural Gas Collars:				
2015				
Collar contracts:				
Call Options	3,640,000	$ 4.82	$ 4.51	$ 5.13
Put Options	3,640,000	$ 3.81	$ 3.50	$ 4.00
Natural Gas Swaps:				
2015				
Swap contracts:	18,580,000	$ 3.12	$ 2.72	$ 3.53
2016				
Swap contracts:	22,450,000	$ 3.18	$ 3.03	$ 3.41

NOTE 5—FAIR VALUE MEASUREMENT

ASC 820, *Fair Value Measurement*, defines fair value 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 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 Company’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 Company’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 the fair value hierarchy for the three months ended March 31, 2015 or the year ended December 31, 2014.

Fair Value on a Recurring Basis

The Company estimated the fair value of derivative 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 – Derivatives and Financial Instruments for further discussion.

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

	Fair Value Measurements Using			Effect of Counterparty Netting	Total
	Level 1	Level 2	Level 3		
			(In thousands)		
As of March 31, 2015					
Financial Assets					
Commodity derivative instruments	$ —	$ 40,047	$ —	$ (342)	$ 39,705
Financial Liabilities					
Commodity derivative instruments	—	379	—	(342)	$ 37
As of December 31, 2014					
Financial Assets					
Commodity derivative instruments	$ —	$ 37,656	$ —	$ (185)	$ 37,471
Financial Liabilities					
Commodity derivative instruments	—	185	—	(185)	$ —

Fair Value on a Non-Recurring Basis

The determination of the fair values of proved and unproved properties acquired in purchase transactions are prepared by estimating discounted cash flow projections. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, and a market-based weighted average cost of capital.

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach. 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. Significant Level 3 assumptions used to determine fair value include estimates of proved reserves, future commodity prices, the timing and amount of future production and capital expenditures, and a discount rate commensurate with the risk associated with the respective oil and natural gas properties.

The Company's estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no significant changes in valuation techniques or related inputs as of March 31, 2015 or December 31, 2014.

The following table presents information about the Company's assets measured at fair value on a non-recurring basis:

	Fair Value Measurements Using			Net Book Value	Impairment Loss
	Level 1	Level 2	Level 3		
			(In thousands)		
As of March 31, 2015					
Impaired oil and natural gas properties	$ —	$ —	$ 17,826	$ 31,293	$ 13,467
As of December 31, 2014					
Impaired oil and natural gas properties	$ —	$ —	$ 81,864	$ 199,794	$ 117,930

The estimated fair value of all debt as of March 31, 2015 and December 31, 2014 approximated the carrying value. These fair values, which are Level 3 measurements, were estimated based on the Company's incremental borrowing rates for similar types of borrowing arrangements, when quoted market prices were not available. The estimated fair values of the Company's financial instruments are not necessarily indicative of the amounts that would be realized in a current market exchange.

NOTE 6—RELATED PARTY TRANSACTIONS

The Company executed promissory notes dated April 15, 2010, in the amount of $0.5 million to officers of the Company. The promissory notes related to the acquisition of a partnership interest in a former affiliate by the officers, and the notes were collateralized by a security interest in the Company. The aggregate outstanding note balance and interest receivable of $0.1 million was received during the quarter ended March 31, 2014.

NOTE 7—COMMITMENTS AND CONTINGENCIES

Environmental Matters

The Company'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 Company does not consider the estimated remediation costs that could result from any environmental site assessments to be significant to the consolidated balance sheet or statement of operations of the Company. No provision for potential remediation costs is reflected in the consolidated financial statements.

Litigation

From time to time, the Company is involved in legal actions and claims arising in the ordinary course of business. The Company believes these claims will be resolved without material adverse effect to the Company's consolidated balance sheet, statement of operations or cash flows.

NOTE 8—CREDIT FACILITY

In September 2006, the Company entered into a credit agreement (the "Senior Line of Credit") with a syndicate of lenders. During the first quarter of 2012, the Senior Line of Credit was amended to extend the term of the facility to February 3, 2017, at which time all unpaid principal and interest is due. On June 28, 2013, the terms of the Senior Line of Credit were amended to increase the maximum credit amount from the original $600.0 million to $1.0 billion. The borrowing base was $700.0 million at both March 31, 2015 and December 31, 2014, respectively. Our semi-annual borrowing base redetermination process resulted in a decrease of the borrowing base to $600.0 million, effective April 10, 2015. The borrowing base is based on the value of the Company's oil and natural gas properties. Proceeds from the Senior Line of Credit are used for the acquisition of oil and natural gas properties and for other general business purposes.

On January 23, 2015, the Senior Line of Credit was amended and restated. Borrowings under the Senior Line of Credit bear interest at LIBOR plus a margin between 1.50% and 2.50%, or prime rate plus a margin between 0.50% and 1.50%, with the margin depending on the borrowing base utilization percentage of the loan. The prime rate is determined to be the higher of the financial institution's prime rate or the federal funds effective rate plus 0.50% per annum. The weighted average interest rate of the Senior Line of Credit was 2.18% and 2.41% as of March 31, 2015 and December 31, 2014, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375% if the borrowing base utilization percentage is less than 50%, or 0.50% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Senior Line of Credit is secured by a majority of the Company's oil and natural gas production and assets.

The Senior Line of Credit contains various restrictions on future borrowings, leases and sales of assets. Additionally, the Senior Line of Credit requires the Company 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. As of March 31, 2015, the Company was in compliance with all financial covenants in the Senior Line of Credit.

The aggregate principal balance outstanding was $389.0 million and $394.0 million at March 31, 2015 and December 31, 2014, respectively. The unused portion of the available borrowings under the Senior Line of Credit was $311.0 million and $306.0 million at March 31, 2015 and December 31, 2014, respectively. Refer to Note 1 – Business and Basis of Presentation for discussion of the use of proceeds from the IPO that occurred subsequent to March 31, 2015.

NOTE 9—REDEEMABLE PREFERRED UNITS

The Company has 117,980 and 157,203 preferred units outstanding with a book value of $120.9 million and $161.2 million as of March 31, 2015 and December 31, 2014, respectively, which includes accrued and unpaid dividends of $2.9 million and $4.0 million as of March 31, 2015 and December 31, 2014, respectively. The preferred units are classified as mezzanine equity on the consolidated balance sheets since redemption is outside the control of the Company. The preferred units are entitled to an annual dividend coupon of 10% of the funded capital of the preferred units payable on a quarterly basis in arrears. The Company accrued dividends on the preferred units of $2.9 million and $3.9 million for the quarters ended March 31, 2015 and 2014, respectively.

The preferred units are convertible into common units at any time at the option of the preferred unitholders. The preferred units have an adjusted initial conversion price of $14.2683 and an adjusted initial conversion rate of 70.0858 common units per preferred unit, which reflects the reverse split described in Note 1 – Business and Basis of Presentation but does not give pro forma effect to the capital restructuring related to the IPO. In the event the preferred unitholders have not converted all of the preferred units by December 31, 2014, the owners of the preferred units can elect to have the Company redeem up to 25% per year of its preferred units at face value, plus any accrued and unpaid dividends, on December 31 of each year from 2014 to 2017. The Company shall have the right, at its sole option, to redeem an amount of preferred units equal to the units being redeemed by an owner of preferred units on each December 31. Any amount of a given year's 25% of preferred units not redeemed on December 31 shall automatically convert to common units on January 1 of the following year. On January 1, 2015 and during the quarter ended March 31, 2015, 39,223 preferred units totaling $39.2 million were automatically converted into 2,748,974 common units. No preferred units were converted into common units during the quarter ended March 31, 2014.

NOTE 10—EARNINGS PER UNIT

Class A and Class B common units have been combined as a single class for purposes of basic and diluted earnings per unit ("EPU") as they contain the same economic rights and preferences. The holders of the Company'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 using the two-class method. For the periods presented, the amount of earnings allocated to the participating restricted common units was not material. The redeemable preferred units can be converted into 8.3 million common units and 11.0 million common units as of March 31, 2015 and 2014, respectively. At March 31, 2015 and 2014, if the redeemable preferred units were converted to common units, their effect would be anti-dilutive. Therefore, the redeemable preferred units are not included in the diluted EPU calculation. The following table reflects the retrospective application of the reverse split described in Note 1 – Business and Basis of Presentation but does not give pro forma effect to the capital restructuring related to the IPO.

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

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
	(In thousands, except per unit amounts)	
Net income	$ 17,299	$ 69,884
Net (income) loss attributable to noncontrolling interests	(9)	3
Dividends on preferred units	(2,909)	(3,882)
Net income attributable to the general partner and limited partners	$ 14,381	$ 66,005
Allocation of net income attributable to:		
General partner interest	$ —	$ —
Common limited partner interest	14,381	66,005
	$ 14,381	$ 66,005
Net income attributable to limited partners per unit:		
Per common limited partner unit (basic and diluted)	$ 0.09	$ 0.40
Weighted average common limited partner units outstanding (basic and diluted)	167,452	164,585

NOTE 11—SUBSEQUENT EVENTS

On April 10, 2015, the borrowing base for the Company's senior line of credit was redetermined and set at $600.0 million by the lenders.

On April 14, 2015, the Company paid distributions totaling $56.3 million to the holders of common units and $2.9 million to the holders of the Preferred Units.

On May 6, 2015, the Company completed its initial public offering of 22,500,000 common units representing limited partner interests at a price to the public of $19.00 per common unit. See Note 1 – Business and Basis of Presentation for further discussion of the IPO and related transactions.

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

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q, as well as the historical consolidated financial statements of our accounting predecessor for financial reporting purposes, Black Stone Minerals Company, L.P., included in our final prospectus (the "Prospectus") dated April 30, 2015 and filed with the SEC, pursuant to Rule 424(b) under the Securities Act, on May 1, 2015. 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."

Unless the context clearly indicates otherwise, references in this Quarterly Report on Form 10-Q to "BSM," the "Company," "we," "our," "us," or similar terms for time periods prior to the IPO refer to Black Stone Minerals Company, L.P. and its subsidiaries, the predecessor for accounting purposes. For time periods subsequent to the IPO, these terms refer to Black Stone Minerals, L.P. and its subsidiaries.

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;
- regional supply and demand factors, delays, or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete, and integrate acquisitions;
- general economic, business, or industry conditions;
- competition in the oil and natural gas industry;
- 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;
- the availability of transportation facilities;
- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;
- 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; 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 Prospectus.

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 of oil and natural gas mineral interests in the United States. Our principal business is maximizing the value of our existing portfolio of mineral and royalty assets through active management and expanding our asset base through acquisitions of additional mineral and royalty interests. We maximize value through marketing our mineral assets for lease, creatively structuring those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working-interest basis. Our primary business objective is to grow our reserves, production, and cash generated from operations over the long term, while paying, to the extent practicable, a growing quarterly distribution to our unitholders.

As of March 31, 2015, our mineral and royalty interests consisted of mineral interests in approximately 14.5 million acres, with an average 48.1% ownership interest in that acreage, nonparticipating royalty interests in 1.2 million acres, and overriding royalty interests in 1.4 million acres. These non-cost-bearing interests included ownership in approximately 40,000 producing wells. We also own non-operated working interests. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when the oil and natural gas production from the associated acreage is sold. 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

Initial Public Offering

On May 6, 2015, we completed our initial public offering of 22,500,000 common units representing limited partner interests at a price to the public of $19.00 per common unit. We received proceeds of approximately $391.6 million from the sale of these common units, net of underwriting discount, structuring fee, and estimated offering expenses (including costs previously incurred and capitalized). We used the net proceeds from the IPO to repay substantially all indebtedness outstanding under our credit facility.

Pursuant to the closing of our IPO, the limited partner interests of our Predecessor were converted into an aggregate of 72,236,664 common units and 94,614,534 subordinated units of BSM at a conversion ratio of 12.9465:1 for 0.4329 common units and 0.5671 subordinated units, and the preferred units of our Predecessor were converted into an aggregate of 117,963 preferred units of BSM at a conversion ratio of one to one.

Business Environment

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

Commodity Prices

Oil and natural gas prices have been historically volatile based upon the dynamics of supply and demand. In the second half of 2014, oil prices began a rapid decline as global supply outpaced demand. In addition, in late November 2014, OPEC announced that it would not adjust its production targets. The oil price decline continued into 2015, with West Texas Intermediate (“WTI”) spot benchmark prices ranging from $43.39 to $53.56 per Bbl during the first quarter of 2015. Due to a variety of global economic factors, the WTI spot benchmark price has recovered as of May 18, 2015 to settle at $59.44 but remains substantially below spot prices seen throughout much of 2014. Natural gas prices continue to be impacted by an imbalance between supply and demand across North America. During the three months ended March 31, 2015, Henry Hub spot natural gas prices ranged from $2.62 per MMBtu to $3.32 per MMBtu. However, the Henry Hub spot price has made a modest recovery from March 31, 2015 and has settled at $3.01 per MMBtu as of May 18, 2015.

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

Average Benchmark Prices	First Quarter 2015	First Quarter 2014
WTI spot oil price ($/Bbl)	$ 47.72	$ 101.57
Henry Hub spot natural gas ($/MMBtu)	$ 2.65	$ 4.48

Source: EIA

We utilize various derivative strategies, which have generally consisted of costless collars and fixed-price swap contracts, to manage the variability in cash flows associated with the projected sale of our oil and natural gas production. We do not enter into derivative instruments for speculative purposes. Throughout 2014, we entered into costless collars to mitigate the impact of price fluctuations. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The sold call option eliminates the initial cost of the purchased put, but places a ceiling price for the commodity being hedged. During the fourth quarter of 2014 and the three months ended March 31, 2015, we entered into fixed-price swap contracts. Under fixed-price swap contracts, a counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap strike price, or we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap strike price. We may employ contractual arrangements other than costless collars and fixed-price swap contracts in the future to mitigate the impact of price fluctuations. In addition, we also expect costs for oilfield services to decline in response to lower commodity prices. We believe that both our hedging contracts and these lower costs will partially mitigate the effects of lower commodity prices in the future.

Rig Count

As we are not an operator, drilling on our acreage is dependent upon the exploration and production companies that lease our acreage. We utilize drilling plans from our operators and monitor rig counts in an effort to identify existing and future leasing and drilling activity on our acreage.

On a weekly basis, Baker Hughes Incorporated, an oilfield services company, releases a detailed report which provides information on the locations of oil and natural gas drilling rigs across the United States, Canada, and the Gulf of Mexico. The weekly rig count report provides insight into industry-wide trends regarding drilling activities in basins across the United States.

The following table shows the U.S. rig count at the close of each of the quarters presented:

	First Quarter 2015	First Quarter 2014
Oil	813	1,487
Natural gas	233	318
Other	2	4
Total	1,048	1,809

Source: Baker Hughes Incorporated

Natural Gas Storage

While a substantial portion of our revenue is derived from sales of oil production attributable to our interests, 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 following table shows natural gas storage volumes by region at the close of each of the quarters presented:

Location	First Quarter 2015 (Bcf)	First Quarter 2014 (Bcf)
East[1]	522	310
West[2]	348	160
Producing[3]	591	352
Total	1,461	822

Source: EIA

1 CT, DE, DC, FL, GA, IA, IL, IN, KY, MA, MD, ME, MI, MO, NC, NE, NH, NJ, NY, OH, PA, RI, SC, TN, VT, VA, WI, and WV
2 AZ, CA, CO, ID, MN, MT, NV, ND, OR, SD, WA, WY, and UT
3 AL, AR, KS, LA, MI, NM, OK, and TX

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 hedges; and
- EBITDA, Adjusted EBITDA, and cash available for distribution.

Volumes of Oil and Natural Gas Produced

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

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

We generally do not market our own production due to our diverse geographical presence, extensive volume of wells, and large number of operators. For the substantial majority of our wells, our oil and natural gas production, including associated natural gas liquids (“NGLs”), is marketed by our operators. The agreements with these operators contain provisions for the marketing of production on both short-term (usually one year or less in duration) and long-term bases. The prices received for oil and natural gas generally vary by geographical area. The relative prices of oil and natural gas are determined by the factors impacting global and regional supply and demand dynamics, such as economic conditions, production levels, 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 NYMEX prices are referred to as differentials. All of our production is derived from properties located in the United States. As a result of our geographic diversification, we are not exposed to concentrated differential risks associated with any single play, trend, or basin.

- *Oil*. The 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 (WTI) is the prevailing domestic oil pricing index. The majority of our oil production is priced on this benchmark with the final realized price affected by both quality and location differentials.

  Quality differentials result from the fact that various types of oil differ from one another due to their different chemical composition, which plays an important role in their refining and subsequent sale as petroleum products. Among other things, there are two characteristics that commonly drive quality differentials: the density of the oil, characterized by the API gravity, and the presence and concentration of impurities, such as sulfur. In general, light crude oil, or oil with a higher API gravity, produces a higher percentage of more valuable products when refined, such as gasoline, and therefore, light crude oil normally sells at a premium to heavy crude oil. Oil with low sulfur content, or “sweet” crude oil, is less expensive to refine and normally sells at a premium to high sulfur-content oil, or “sour” crude oil.

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 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 sulfur, carbon dioxide, and nitrogen. Due to the content of NGLs in high Btu gas, this quality of natural gas nets a higher overall price when compared to a low Btu gas. Natural gas with a higher concentration of impurities will receive a lower price due to 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 fixed-price contracts, fixed-price swaps, costless collars, and other contractual arrangements. In addition, we currently employ a "rolling hedge" strategy whereby we do not execute all of our hedges at the same time but instead execute new trades as older hedges settle or expire. The impact of these derivative instruments could affect the amount of revenue we ultimately record. Our open oil and natural gas derivative contracts as of March 31, 2015 are detailed within Note 4 to our consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q. Our credit facility agreement limits the extent to which we can hedge our future production. Under the terms of our credit agreement, we are able to hedge estimated production from our proved developed producing reserves based on our most recently completed reserve report provided to our lenders. As of March 31, 2015, we have hedged 97.3 % and 97.4% of our oil production that can be hedged pursuant to the stipulations in our credit agreement for the remainder of 2015 and 2016, respectively, and 97.8% and 98.8% of our estimated natural gas production from our proved developed producing reserves for the remainder of 2015 and 2016, respectively.

Non-GAAP Financial Measures

EBITDA, Adjusted EBITDA, and cash available for distribution 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 EBITDA as net income (loss) before interest expense, income taxes and depreciation, depletion, and amortization. We define Adjusted EBITDA as EBITDA further adjusted for impairment of oil and natural gas properties, accretion of AROs, unrealized gains/losses on derivative instruments, and non-cash equity-based compensation. We define cash available for distribution as Adjusted EBITDA plus or minus amounts for certain non-cash operating activities, borrowings for capital expenditures, capital expenditures, cash interest expense, and distributions to noncontrolling interests and preferred unitholders.

EBITDA, Adjusted EBITDA, and cash available for distribution do not represent and should not be considered an alternative to, or more meaningful than, net income, income from operations, cash flows from operating activities, or any other measure of financial performance presented in accordance with GAAP as measures of our financial performance. EBITDA, Adjusted EBITDA, and cash available for distribution have important limitations as analytical tools because they exclude some but not all items that affect net income, the most directly comparable GAAP financial measure. Our computation of EBITDA, Adjusted EBITDA, and cash available for distribution may differ from computations of similarly titled measures of other companies.

The following table presents a reconciliation of EBITDA, Adjusted EBITDA, and cash available for distribution to net income, the most directly comparable GAAP financial measure, for the periods indicated.

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
	(Unaudited) (In thousands)	
Net income	$ 17,299	$ 69,884
Adjustments to reconcile to Adjusted EBITDA:		
Add:		
Depreciation, depletion and amortization	27,891	23,134
Interest expense	2,945	3,433
EBITDA	48,135	96,451
Add:		
Impairment of oil and natural gas properties	13,467	—
Accretion of asset retirement obligations	271	147
Unrealized loss on commodity derivative instruments	—	3,911
Equity-based compensation expense	1,243	3,499
Less:		
Unrealized gain on commodity derivative instruments	(2,197)	—
Adjusted EBITDA	60,919	104,008
Adjustments to reconcile to cash generated from operations:		
Add:		
Borrowings to fund capital expenditures	13,206	38,018
Less:		
Deferred revenue	(104)	(2,516)
Cash interest expense	(2,704)	(3,192)
Capital expenditures, net	(13,206)	(38,018)
Cash generated from operations	58,111	98,300
Less:		
Cash paid to noncontrolling interests	(52)	(73)
Preferred unit distributions	(2,909)	(3,882)
Cash generated from operations available for distribution on common units and reinvestment in our business	$ 55,150	$ 94,345

Factors Affecting the Comparability of Our Financial Results

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, because we will incur annual incremental general and administrative expenses as a result of operating as a publicly traded partnership. These incremental expenses include costs associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NYSE listing, independent registered public accounting firm fees, legal fees, investor-relations activities, registrar and transfer agent fees, director-and-officer insurance, and additional compensation. These direct, incremental general and administrative expenses are not included in our historical results of operations.

Results of Operations

Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014

Revenues

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

	Three Months Ended March 31,			
	2015		2014	
	(Unaudited) (Dollars in thousands, except for realized prices)			
Production:				
Oil and condensate (MBbls)[1]		827		662
Natural gas (MMcf)[1]		10,785		9,741
Equivalents (MBoe)[2]		2,625		2,286
Realized prices:				
Oil and condensate ($/Bbl)	$	43.73	$	90.09
Natural gas ($/Mcf)[1]	$	2.93	$	5.98
Combined equivalents ($/Boe)[2]	$	25.83	$	51.55
Revenue:				
Oil and condensate sales	$	36,163	$	59,642
Natural gas and natural gas liquids sales		31,640		58,206
Gain (loss) on commodity derivative instruments		19,647		(5,995)
Lease bonus and other income		3,611		15,559
Total revenue	$	91,061	$	127,412

1 As a mineral-and-royalty-interest owner, we are often provided insufficient and inconsistent data 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. As such, the realized prices account for all sales attributable to NGLs. The oil and condensate production volumes and natural gas production volumes do not include NGL volumes.

2 "Btu-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of six Mcf of natural gas per barrel of "oil equivalent," which is based on approximate energy equivalency and does not reflect the price or value relationship between oil and natural gas.

Total revenues for the quarter ended March 31, 2015 decreased $36.4 million, or 28.5%, compared to the corresponding period ended March 31, 2014. Production for the quarter ended March 31, 2015 averaged 29.2 MBoe per day, an increase of 3.8 MBoe per day, or 14.8%, compared to the corresponding period ended March 31, 2014. The decrease in total revenues is primarily due to a decline of $71.2 million from lower realized commodity prices and $11.9 million from lower lease bonus, partially offset by $21.1 million from higher production volumes and $25.6 million from gains on commodity derivative instruments.

Oil and condensate sales. Oil and condensate sales during the period were $23.5 million, or 39.4%, lower than the corresponding period in 2014 primarily due to a decrease in realized prices. Our mineral-and-royalty-interest oil volumes accounted for 76.1% and 70.3% of total oil and condensate volumes for the three months ended March 31, 2015 and 2014, respectively. The 35.2% increase in mineral-and-royalty-interest oil volumes in the first quarter of 2015 relative to the corresponding period in 2014 was driven primarily by production increases from new wells in the Bakken, Three Forks, and Eagle Ford Shale plays. Our working-interest oil volumes increased by 0.7% to 197.9 MBbls during the first quarter of 2015 versus the same period in 2014 primarily due to volumes added from new wells in the Bakken and Three Forks Shale plays. The revenue impact of a 51.5% decline in realized oil prices was partially offset by the increase in oil and condensate production.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased by $26.6 million, or 45.6%, for the quarter ended March 31, 2015 as compared to the same period for 2014. A 50.9% decrease in the realized natural gas price for the first three months of 2015 versus the corresponding period in 2014 was primarily responsible for the decline in our natural gas revenues. The unfavorable price variance was partially offset by a 10.7% increase in produced volumes. This production increase was primarily generated by production from new wells in the Haynesville and Bossier Shale plays and the Wilcox play. Mineral-and-royalty-interest production accounted for 62.1% and 68.5% of our natural gas volumes for the quarters ending March 31, 2015 and 2014, respectively.

Gain (loss) on commodity derivative instruments. In 2014, global oil inventories increased to the largest level since 2008. Falling demand caused oil prices to decline sharply during the latter half of the year. In addition, robust domestic natural gas production and a warmer than normal December contributed to lower than average natural gas storage withdrawals. Natural gas prices reflect the abundant supplies. Commodity prices remained depressed throughout the first quarter of 2015. We use derivative instruments to mitigate the risk and resulting impact of such volatility. During the first quarter of 2015, we recognized $13.0 million of combined gains from oil commodity contracts, of which $11.5 million were realized, compared to a recognized loss of $1.6 million in the same period of 2014. During the first quarter of 2015, we recognized $6.6 million of gains from natural gas commodity contracts, of which $5.9 million were realized, compared to a recognized loss of $4.4 million in the same period of 2014.

*Lease bonus and other income.*When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus and other income decreased $11.9 million, or 76.8%, for the quarter ended March 31, 2015 as compared to the same period in 2014. In the first quarter of 2014, there were successful closings of several significant leases in the Canyon Lime and Canyon Wash plays in north Texas and the Permian Basin; these transactions were not replicated in the corresponding period of 2015. The timing of lease-bonus transactions is highly unpredictable and may vary significantly from quarter to quarter. Historically, lease-bonus income has been higher in the third and fourth quarters of the calendar year.

Operating Expenses

Lease operating expenses and other. Lease operating expenses include normally recurring expenses necessary to produce hydrocarbons from our non-operated working interests in oil and natural gas wells, non-recurring well workovers, repair-related expenses, and exploration expenses. Lease operating expense and other increased $1.3 million, or 26.8%, for the quarter ended March 31, 2015 as compared to the same period in 2014, primarily due to costs associated with higher production volumes for both oil and natural gas.

Production costs and ad valorem taxes. Production, or severance, 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 March 31, 2015, production costs and ad valorem taxes decreased by $2.3 million, or 22.0%, over the quarter ended March 31, 2014, generally as a result of lower realized prices and estimated mineral reserve valuations.

Depreciation, depletion, and amortization. Depletion is the amount of cost basis of oil and natural gas properties at the beginning of a period attributable to the volume of hydrocarbons extracted during such period, calculated on a units-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We have historically adjusted our depletion rates in the fourth quarter of each year based upon the year-end reserve report and other times during the year when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization increased $4.8 million, or 20.6%, for the quarter ended March 31, 2015 as compared to the same period in 2014, primarily due to higher production rates. In addition, the average depletion rate by field increased because of downward reserve revisions, as a result of changes in estimates of future commodity prices, lease operating expenses, and natural gas shrinkage.

Impairment of oil and natural gas properties. Individual categories of oil and natural gas properties are assessed periodically to determine if the net book value for these properties has been impaired. Management periodically conducts an in-depth evaluation of the cost of property acquisitions, successful exploratory wells, development activities, unproved leasehold, and mineral interests to identify impairments. Impairments totaled $13.5 million for the quarter ended March 31, 2015 primarily due to changes in reserve values resulting from further drops in commodity prices during the period and other factors. There were no impairments for the first quarter of 2014.

General and administrative. General and administrative expenses are costs not directly associated with the production of oil and natural gas and include the cost of executives and employees and related benefits, office expenses, and fees for professional services. For the quarter ended March 31, 2015, general and administrative expenses decreased by $0.6 million, or 4.1%, as compared to the same period in 2014. In 2015, costs attributable to our long-term incentive plan were lower than in the corresponding prior period.

Accretion of asset retirement obligations. An asset retirement obligation (“ARO”) represents an obligation to perform site reclamation, to dismantle production or processing facilities, or to plug and abandon wells. To determine the current amount of an ARO, the estimated future cost to satisfy the abandonment obligation, using current prices that are escalated by an assumed inflation factor to the estimated settlement date, is discounted back to the date that the abandonment obligation was incurred. After recording this cost, an ARO is accreted to its future estimated value in order to match the timing of expenses with the periods in which they occurred. Accretion expense was $0.3 million, or 84.4% higher for the quarter ended March 31, 2015 than the corresponding period of 2014. This increase was due to the current period impact of revisions in estimated future costs made during the fourth quarter of 2014.

Interest expense. Interest expense decreased by $0.5 million, or 14.2%, due to lower borrowings under our credit facility. Outstanding borrowings during the first quarter of 2015 were lower than the first quarter of 2014, primarily due to decreased expenditures for acquisitions and drilling activity as compared to the corresponding prior period.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are the net proceeds retained from cash generated from operations, borrowings under our credit facility, and proceeds from any future issuances of equity and debt. Our primary uses of cash are for distributions to our unitholders and for capital expenditures, including the acquisition of mineral and royalty and working interests, and the development of our oil and natural gas properties.

The board of directors of our general partner has adopted a policy pursuant to which distributions equal in amount to the applicable minimum quarterly distribution will be paid on each common and subordinated 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. We believe that we will generate sufficient cash from operations to pay the required distribution on the preferred units and the applicable minimum quarterly distributions on all the common and subordinated units outstanding. However, we do not have a legal or contractual obligation to pay distributions quarterly or on any other basis, at the applicable minimum quarterly distribution rate or at any other rate, and there is no guarantee that we will pay distributions to our unitholders in any quarter. The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time.

It is our intent, for at least the next several years, to finance most of our acquisitions and working-interest capital needs with cash generated from operations, borrowings from our credit facility, and, in certain circumstances, proceeds from future equity and debt issuances. Replacement capital expenditures are expenditures necessary to replace our existing oil and natural gas reserves or otherwise maintain our asset base over the long-term. Like a number of other master limited partnerships, we are required by our partnership agreement to retain cash from our operations in an amount equal to our estimated replacement capital requirements. We have set our initial distribution rate at a level we believe will allow us to retain in our business sufficient cash generated from our operations to satisfy our replacement capital expenditures needs and to fund a portion of our growth capital expenditures. The board of directors of our general partner is responsible for establishing the amount of our estimated replacement capital expenditures.

At the beginning of each calendar year, we establish a capital budget and then review it throughout the year. Our capital budgets are created based upon our estimate of internally generated cash and the ability to borrow and raise additional capital. Actual capital expenditure levels will vary, in part, based on actual internally generated cash, actual wells proposed by our operators for our participation, and the successful closing of acquisitions. The timing, size, and nature of acquisitions are unpredictable.

Cash Flows

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

	Three Months Ended March 31, 2015	Three Months Ended March 31, 2014
	(Unaudited) (In thousands)	
Cash flows provided by operating activities	$ 74,359	$ 74,163
Cash flows used in investing activities	$ (13,206)	$ (38,018)
Cash flows used in financing activities	$ (67,588)	$ (48,290)

Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014

Operating Activities. Our operating cash flow is dependent, in large part, on our production, realized commodity prices, leasing revenues, and operating expenses. Our cash flow from operations of $74.4 million for the quarter ended March 31, 2015 increased slightly from $74.2 million for the same period in 2014. The increase was primarily due to a difference of $19.5 million in operating cash flows related to the settlement of commodity derivative instruments as compared to the corresponding period in 2014 partially offset by lower cash collections of $19.4 million related to oil and natural gas sales and lease bonus as compared to the corresponding period in 2014.

Investing Activities. Net cash used in investing activities decreased by $24.8 million in the first quarter of 2015 as compared to the corresponding period in 2014 because no acquisitions were closed during the first quarter of 2015. Capital expenditures for our working interests, net of sale proceeds, decreased by $0.8 million for the quarter ended March 31, 2015 versus the corresponding period in 2014.

Financing Activities. For the quarter ended March 31, 2015, net cash used in financing activities increased $19.3 million compared to the corresponding period in 2014. This increase is primarily due to net repayments of $5.0 million made under our credit facility during the first quarter of 2015 compared to net borrowings of $11.5 million during the same period in 2014.

Capital Expenditures

Our 2015 capital budget for drilling expenditures is $40.1 million. Approximately 65% and 14% of our drilling capital budget will be spent in the Haynesville/Bossier and Bakken/Three Forks Shale plays, respectively, with the remainder spent in various plays including the Wilcox and Granite Wash plays. During the first quarter of 2015, we spent approximately $13.6 million primarily in the Haynesville/Bossier and Bakken/Three Forks Shale plays and the Wilcox play.

Credit Facility

On January 23, 2015, we amended and restated our $1.0 billion senior secured revolving credit agreement. Under this third amended and restated credit facility, the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base, which is determined based on the value of our oil and natural gas properties. The third amended and restated credit facility will terminate on February 3, 2017. Borrowings under the third amended and restated credit facility may be used for the acquisition of properties, cash distributions, and other general corporate purposes. Our semi-annual borrowing base redetermination process resulted in a decrease of the borrowing base to $600.0 million, effective April 10, 2015. We do not believe the decrease in our borrowing base resulting from the redetermination will adversely affect our liquidity. Our next borrowing base redetermination is scheduled for October 2015. As of March 31, 2015, we had outstanding borrowings of $389.0 million at a weighted-average interest rate of 2.18%. We used net proceeds from our IPO in May 2015 to repay substantially all indebtedness outstanding under our credit facility.

The borrowing base under the third amended and restated credit agreement is redetermined semi-annually, on April 1 and October 1 of each year, by the administrative agent, taking into consideration the estimated loan value of our oil and gas properties consistent with the administrative agent’s normal oil and gas lending criteria. The administrative agent’s proposed redetermined borrowing base must be approved by all lenders if it increases our existing borrowing base, and by two-thirds of the lenders if it decreases or maintains our existing borrowing base. In addition, we and the lenders (at the election of two-thirds of the lenders) each have discretion once in between scheduled redeterminations, to have the borrowing base redetermined.

Outstanding borrowings under the third amended and restated credit agreement bear interest at a floating rate elected by us equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 1-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of borrowings outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year 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 LIBOR 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 facility is secured by liens on substantially all of our properties.

The third amended and restated credit agreement contains various affirmative, negative, and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements, and require the maintenance of certain financial ratios. The third amended and restated credit agreement contains two financial covenants: total debt to EBITDAX of 3.5:1.0 or less; and current assets to current liabilities of 1.0:1.0 or greater. Distributions are not permitted if there is a default under the third amended and restated credit agreement (including due to a failure to satisfy one of the financial covenants) or during any time that our borrowing base is lower than the loans outstanding under the credit facility. The lenders have the right to accelerate all of the indebtedness under the third amended and restated credit facility upon the occurrence and during the continuance of any event of default, and the third amended and restated credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods. As of March 31, 2015, we were in compliance with all debt covenants.

Contractual Obligations

As of March 31, 2015, there have been no significant changes to our contractual obligations previously disclosed in the Prospectus.

Off-Balance Sheet Arrangements

As of March 31, 2015, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of March 31, 2015, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in the Prospectus.

New and Revised Financial Accounting Standards

The effects of new accounting pronouncements are discussed in the notes to the consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil and natural gas production by our operators. Realized pricing is primarily driven by the prevailing worldwide price for oil and U.S. spot market prices for natural gas production. Pricing for oil and natural gas production has been unpredictable for several years, 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 have executed commodity derivative contracts to reduce our exposure to price risk in the spot market for oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settle monthly in cash based on a designated floating price. The designated floating price has been based off the NYMEX index 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 Notes 4 and 5 to the consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

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. At March 31, 2015, we had nine counterparties, all of which are rated Baa2 or better by Moody's. Six of our counterparties 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 customers 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. As of March 31, 2015, we had $389.0 million of outstanding borrowings under our credit facility, bearing interest at a weighted-average interest rate of 2.18%. 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 approximately $1.0 million for the quarter ended March 31, 2015, assuming that our indebtedness remained constant throughout the quarter. 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

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 March 31, 2015.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2015 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, you should carefully consider the risks under the heading "Risk Factors" in the Prospectus. There has been no material change in our risk factors from those described in the Prospectus. 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

On May 6, 2015, we completed our initial public offering of 22,500,000 common units representing limited partner interests at a price to the public of $19.00 per common unit. The offering was made pursuant to a registration statement on Form S-1, as amended, filed with the SEC and declared effective on April 30, 2015 (SEC File No. 333-202875). The underwriters were Barclays Capital Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC, Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., Scotia Capital (USA) Inc. and Simmons & Company International. We received proceeds of approximately $391.6 million from the sale of these common units, net of underwriting discount, structuring fee, and estimated offering expenses (including costs previously incurred and capitalized). We used the net proceeds from the IPO to repay substantially all indebtedness outstanding under our credit facility.

Item 6. Exhibits

The information required by this Item 6 is set forth in the Index to Exhibits accompanying this Quarterly Report on Form 10-Q and is incorporated herein by reference.

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: June 4, 2015

By: /s/ Thomas L. Carter, Jr.
Thomas L. Carter, Jr.
President and Chief Executive Officer
(Principal Executive Officer)

Date: June 4, 2015

By: /s/ Marc Carroll
Marc Carroll
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit Index

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)).
10.1	Third Amended and Restated Credit Agreement among Black Stone Minerals Company, L.P., as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, Bank of America, N.A. and Compass Bank, as Co-Syndication Agents, Wells Fargo Bank, N.A. and Amegy Bank National Association, as Co-Documentation Agents, and a syndicate of lenders dated as of January 23, 2015 (incorporated herein by reference to Exhibit 10.2 to Black Stone Minerals, L.P.'s Registration Statement on Form S-1 filed on March 19, 2015 (SEC File No. 333-202875)).
*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	XBRL Instance Document
*101.SCH	XBRL Schema Document
*101.CAL	XBRL Calculation Linkbase Document
*101.LAB	XBRL Label Linkbase Document
*101.PRE	XBRL Presentation Linkbase Document
*101.DEF	XBRL Definition Linkbase Document

* Filed or furnished herewith.

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)) 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. 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

    c. 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: June 4, 2015

/s/ Thomas L. Carter, Jr.
Thomas L. Carter, Jr.
President and 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, Marc Carroll, 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)) 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. 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

   c. 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: June 4, 2015

/s/ Marc Carroll
Marc Carroll
Senior Vice President and 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 "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Thomas L. Carter, Jr., Chief Executive Officer of the Company, and Marc Carroll, Chief Financial Officer of the Company, 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 Company.

Date: June 4, 2015

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

Date: June 4, 2015

/s/ Marc Carroll
Marc Carroll
Senior Vice President and Chief Financial Officer
Black Stone Minerals GP, L.L.C.,
the general partner of Black Stone Minerals, L.P.