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

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended June 30, 2016

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) 445-3200
(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 August 5, 2016, there were 95,740,308 common limited partner units, 95,189,076 subordinated limited partner units, and 52,691 preferred units of the registrant outstanding.

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

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

	June 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9,770	$ 13,233
Accounts receivable	53,568	41,246
Commodity derivative assets	13,412	48,260
Prepaid expenses and other current assets	2,160	856
TOTAL CURRENT ASSETS	78,910	103,595
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, at cost, using the successful efforts method of accounting, includes unproved properties of $609,783 and $524,563 at June 30, 2016 and December 31, 2015, respectively	2,646,558	2,482,211
Accumulated depreciation, depletion, amortization, and impairment	(1,601,401)	(1,543,796)
Oil and natural gas properties, net	1,045,157	938,415
Other property and equipment, net of accumulated depreciation of $14,693 and $14,660 at June 30, 2016 and December 31, 2015, respectively	151	179
NET PROPERTY AND EQUIPMENT	1,045,308	938,594
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	2,612	19,247
TOTAL ASSETS	$ 1,126,830	$ 1,061,436
LIABILITIES, MEZZANINE EQUITY AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 5,160	$ 5,036
Accrued liabilities	36,475	58,003
Commodity derivative liabilities	1,835	—
TOTAL CURRENT LIABILITIES	43,470	63,039
LONG-TERM LIABILITIES		
Credit facility	285,000	66,000
Accrued incentive compensation	5,264	7,902
Commodity derivative liabilities	1,101	—
Deferred revenue	3,477	3,257
Asset retirement obligations	11,240	10,585
TOTAL LIABILITIES	349,552	150,783
COMMITMENTS AND CONTINGENCIES (Note 8)		
MEZZANINE EQUITY		
Partners' equity - redeemable preferred units, 53 and 77 units outstanding at June 30, 2016 and December 31, 2015, respectively	54,001	79,162
EQUITY		
Partners' equity - general partner interest	—	—
Partners' equity - common units, 95,736 and 96,162 units outstanding at June 30, 2016 and December 31, 2015, respectively	511,862	574,648
Partners' equity - subordinated units, 95,189 and 95,057 units outstanding at June 30, 2016 and December 31, 2015, respectively	210,332	255,699
Noncontrolling interests	1,083	1,144
TOTAL EQUITY	723,277	831,491
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 1,126,830	$ 1,061,436

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

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

	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
REVENUE				
Oil and condensate sales	$ 34,553	$ 46,293	$ 61,801	$ 82,456
Natural gas and natural gas liquids sales	21,607	28,968	46,719	60,608
Gain (loss) on commodity derivative instruments	(30,733)	(18,627)	(20,107)	1,020
Lease bonus and other income	15,142	8,169	16,537	11,780
TOTAL REVENUE	40,569	64,803	104,950	155,864
OPERATING (INCOME) EXPENSE				
Lease operating expense	4,283	5,483	9,172	11,616
Production costs and ad valorem taxes	7,012	9,819	14,074	18,075
Exploration expense	629	158	637	197
Depreciation, depletion and amortization	29,202	32,235	50,923	60,126
Impairment of oil and natural gas properties	679	118,362	6,775	131,829
General and administrative	18,134	19,718	35,535	34,536
Accretion of asset retirement obligations	200	269	474	540
Gain on sale of assets, net	(92)	(17)	(4,772)	(24)
TOTAL OPERATING EXPENSE	60,047	186,027	112,818	256,895
INCOME FROM OPERATIONS	(19,478)	(121,224)	(7,868)	(101,031)
OTHER INCOME (EXPENSE)				
Interest and investment income	38	27	191	28
Interest expense	(1,443)	(1,715)	(2,491)	(4,660)
Other income	73	146	107	196
TOTAL OTHER EXPENSE	(1,332)	(1,542)	(2,193)	(4,436)
NET LOSS	(20,810)	(122,766)	(10,061)	(105,467)
NET (INCOME) LOSS ATTRIBUTABLE TO PREDECESSOR	—	16,849	—	(450)
NET LOSS ATTRIBUTABLE TO NONCONTROLLING INTERESTS SUBSEQUENT TO INITIAL PUBLIC OFFERING	9	140	7	140
DISTRIBUTIONS ON REDEEMABLE PREFERRED UNITS SUBSEQUENT TO INITIAL PUBLIC OFFERING	(1,310)	(1,810)	(3,114)	(1,810)
NET LOSS ATTRIBUTABLE TO THE GENERAL PARTNER AND COMMON AND SUBORDINATED UNITS SUBSEQUENT TO INITIAL PUBLIC OFFERING	$ (22,111)	$ (107,587)	$ (13,168)	$ (107,587)
ALLOCATION OF NET INCOME (LOSS) SUBSEQUENT TO INITIAL PUBLIC OFFERING ATTRIBUTABLE TO:				
General partner interest	$ —	$ —	$ —	$ —
Common units	(7,445)	(54,109)	862	(54,109)
Subordinated units	(14,666)	(53,478)	(14,030)	(53,478)
	$ (22,111)	$ (107,587)	$ (13,168)	$ (107,587)
NET INCOME (LOSS) ATTRIBUTABLE TO LIMITED PARTNERS PER COMMON AND SUBORDINATED UNIT:				
Per common unit (basic)	$ (0.08)	$ (0.56)	$ 0.01	$ (0.56)
Weighted average common units outstanding (basic)	96,356	96,178	96,418	96,178
Per subordinated unit (basic)	$ (0.15)	$ (0.56)	$ (0.15)	$ (0.56)
Weighted average subordinated units outstanding (basic)	95,189	95,057	95,092	95,057
Per common unit (diluted)	$ (0.08)	$ (0.56)	$ 0.01	$ (0.56)
Weighted average common units outstanding (diluted)	96,418	96,178	96,481	96,178
Per subordinated unit (diluted)	$ (0.15)	$ (0.56)	$ (0.15)	$ (0.56)
Weighted average subordinated units outstanding (diluted)	95,092	95,057	95,092	95,057
DISTRIBUTIONS DECLARED AND PAID SUBSEQUENT TO INITIAL PUBLIC OFFERING:				
Per common unit	$ 0.26250	$ —	$ 0.52500	$ —
Per subordinated unit	$ 0.18375	$ —	$ 0.36750	$ —

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

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

	Common units	Subordinated units	Partners' equity—common units	Partners' equity—subordinated units	Noncontrolling interests	Total equity
BALANCE AT DECEMBER 31, 2015	96,162	95,057	$ 574,648	$ 255,699	$ 1,144	$ 831,491
Restricted units granted, net of forfeitures	956	(38)	—	—	—	—
Equity-based compensation	—	—	8,732	1,176	—	9,908
Conversion of redeemable preferred units	184	241	2,625	3,439	—	6,064
Repurchases of common and subordinated units	(1,566)	(71)	(23,888)	(808)	—	(24,696)
Distributions	—	—	(50,722)	(35,144)	(54)	(85,920)
Charges to partners' equity for accrued distribution equivalent rights	—	—	(395)	—	—	(395)
Net income (loss)	—	—	2,431	(12,485)	(7)	(10,061)
Distributions on redeemable preferred units	—	—	(1,569)	(1,545)	—	(3,114)
BALANCE AT JUNE 30, 2016	95,736	95,189	$ 511,862	$ 210,332	$ 1,083	$ 723,277

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

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

	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (10,061)	$ (105,467)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, and amortization	50,923	60,126
Impairment of oil and natural gas properties	6,775	131,829
Accretion of asset retirement obligations	474	540
Amortization of deferred charges	394	482
(Gain) loss on commodity derivative instruments	20,107	(1,020)
Net cash received on settlement of commodity derivative instruments	33,918	34,155
Equity-based compensation	25,139	7,362
Gain on sale of assets, net	(4,772)	(24)
Changes in operating assets and liabilities:		
Accounts receivable	(6,585)	19,881
Prepaid expenses and other current assets	(1,003)	(912)
Accounts payable and accrued liabilities	(31,859)	(2,273)
Deferred revenue	221	(490)
Settlement of asset retirement obligations	(127)	(105)
NET CASH PROVIDED BY OPERATING ACTIVITIES	83,544	144,084
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to oil and natural gas properties	(36,710)	(32,819)
Purchase of other property and equipment	(5)	(28)
Proceeds from the sale of oil and natural gas properties	177	406
Acquisitions of oil and natural gas properties	(136,340)	(9,574)
NET CASH USED IN INVESTING ACTIVITIES	(172,878)	(42,015)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of common units of Black Stone Minerals, L.P., net of offering costs	—	399,394
Payments for capitalized offering costs	(301)	—
Borrowings under senior line of credit	230,000	123,600
Repayments of borrowings under senior line of credit	(11,000)	(511,600)
Distributions to Predecessor unitholders	—	(112,210)
Distributions to Black Stone Minerals, L.P. common and subordinated unitholders	(85,866)	—
Distributions to preferred unitholders	(3,751)	(6,871)
Distributions to noncontrolling interests	(54)	(122)
Redemptions of redeemable preferred units	(18,461)	—
Repurchases of common and subordinated units	(24,696)	(3,015)
NET CASH PROVIDED BY (USED IN) FINANCING ACTIVITIES	85,871	(110,824)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(3,463)	(8,755)
CASH AND CASH EQUIVALENTS - beginning of the period	13,233	14,803
CASH AND CASH EQUIVALENTS - end of the period	$ 9,770	$ 6,048
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 1,928	$ 4,192

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, L.P. ("BSM" or the "Partnership") 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 $391.5 million from the sale of its common units, net of underwriting discount, structuring fee, and 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."

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. 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 was 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 "Partnership" 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, which make up the vast majority of the asset base, the Partnership's assets also include nonparticipating and overriding royalty interests. All of these interests are non-cost-bearing and are collectively referred to as "mineral and royalty interests." As of June 30, 2016, the Partnership's mineral and royalty interests were located in most of the major onshore oil and natural gas producing basins spread across 41 states and 61 onshore oil and natural gas producing basins of the continental United States. The Partnership 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 Partnership have been prepared in accordance with generally accepted accounting principles ("GAAP") in the United States and pursuant to the rules and regulations of the U.S. Securities and Exchange Commission ("SEC"). These unaudited interim consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with U.S. GAAP. Accordingly, the accompanying unaudited interim consolidated financial statements and related notes should be read in conjunction with the Partnership's consolidated financial statements for the years ended December 31, 2015, 2014, and 2013 included in the Partnership's 2015 Annual Report on Form 10-K. The financial statements include the consolidated results of the Partnership. All intercompany balances and transactions have been eliminated.

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 Partnership. 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 and six months ended June 30, 2016 are not necessarily indicative of the results to be expected for the full year.

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

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

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

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant accounting policies: Our significant accounting policies are disclosed in Note 2 of the Partnership's consolidated financial statements for the years ended December 31, 2015, 2014, and 2013 included in the Partnership's 2015 Annual Report on Form 10-K. There have been no changes in such policies or the application of such policies during the six months ended June 30, 2016.

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 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. In July 2015, the FASB decided to defer the original effective date by one year to be effective for annual reporting periods beginning after December 15, 2017 instead of December 15, 2016 for public entities. The Partnership is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures and has not yet determined the method by which it will adopt the standard.

In February 2016, the FASB issued Accounting Standard Update ("ASU") No. 2016-02, *Leases (Topic 842)*, which requires lessees to recognize the lease assets and lease liabilities classified as operating leases on the balance sheet. The amendment will be effective for reporting periods beginning on or after December 15, 2018, and early adoption is permitted. The Partnership is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-06, *Derivatives and Hedging (Topic 815): Contingent put and call options in debt instruments*, which clarifies the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The amendment will be effective prospectively for reporting periods beginning on or after December 31, 2016, and early adoption is permitted. The Partnership does not expect that the impact of adopting this guidance will be material to the Partnership's consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-08, *Revenue from Contracts with Customers (Topic 606): Principal versus agent considerations (reporting revenue gross versus net)*, which clarifies the implementation guidance on principal versus agent considerations. The amendment will be effective prospectively for reporting periods beginning on or after December 31, 2017, and early adoption is not permitted. The Partnership is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU No. 2016-09, *Compensation – Stock Compensation (Topic 718): Improvements to employee share-based payment accounting*, which includes provisions intended to simplify various aspects related to how share-based compensation payments are accounted for and presented in the financial statements. This amendment will be effective prospectively for reporting periods beginning on or after December 15, 2016, and early adoption is permitted. The Partnership is evaluating the impact that the new accounting guidance will have on its consolidated financial statements and related disclosures.

In June 2016, the FASB issued ASU No. 2016-13, *Financial Instruments – Credit Losses (Topic 326): Measurement of credit losses on financial instruments*, which changes the impairment model for most financial assets and certain other instruments, including trade and other receivables, held-to-maturity debt securities and loans, and requires entities to use a new forward-looking expected loss model that will result in the earlier recognition of allowance for losses. This amendment is effective for fiscal years beginning after December 15, 2019, and early adoption is permitted. Entities will apply the standard's provisions as a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is adopted. The Partnership is evaluating the impact that the new accounting guidance will have on its 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 Partnership's working-interest oil and natural gas properties. The Partnership utilizes current retirement costs to estimate the expected cash outflows for retirement obligations. The Partnership estimates the ultimate productive life of its properties, a credit-adjusted risk-free 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 Partnership's ARO liability during the period:

	For the six months ended June 30, 2016 (In thousands)
Beginning asset retirement obligations	$ 10,585
Liabilities incurred	172
Liabilities settled	(127)
Accretion expense	474
Revisions	136
Ending asset retirement obligations	$ 11,240

NOTE 4—ACQUISITIONS

Acquisitions of proved oil and natural gas properties and working interests are considered business combinations and are recorded at their estimated fair value as of the acquisition date. Acquisitions of unproved oil and natural gas properties are considered asset acquisitions and are recorded at historical cost.

On January 8, 2016, the Partnership acquired mineral and royalty interests in the Permian Basin for $10.0 million.

On June 15, 2016, the Partnership acquired an oil and natural gas mineral package primarily located in Weld County, Colorado for $34.0 million. The following table summarizes the fair values assigned to the properties acquired:

	(In thousands)
Proved oil and natural gas properties	$ 18,948
Unproved oil and natural gas properties	14,082
Net working capital	1,038
Asset retirement obligations	(50)
Purchase price allocation	$ 34,018

On June 17, 2016, the Partnership acquired a diverse oil and natural gas mineral package from Freeport-McMoRan Oil and Gas, Inc. for $87.9 million. The following table summarizes the fair values assigned to the properties acquired:

	(In thousands)
Proved oil and natural gas properties	$ 20,637
Unproved oil and natural gas properties	65,745
Net working capital	1,488
Purchase price allocation	$ 87,870

NOTE 5—DERIVATIVES AND FINANCIAL INSTRUMENTS

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

As of June 30, 2016, the Partnership's open derivative contracts consisted of only fixed-price-swap contracts. A fixed-price-swap contract between the Partnership and the counterparty specifies a fixed commodity price and a future settlement date. The Partnership will receive from, or pay to, the counterparty the difference between the fixed-swap price and the market price on the settlement date. 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. All derivative instruments that have not yet been settled in cash are reflected as either derivative assets or liabilities in the Partnership's accompanying consolidated balance sheets as of June 30, 2016 and December 31, 2015. See Note 6 – Fair Value Measurement for further discussion.

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

As of June 30, 2016				
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(In thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 15,778	$ (2,366)	$ 13,412
Long-term asset	Deferred charges and other long-term assets	212	(179)	33
Total assets		$ 15,990	$ (2,545)	$ 13,445
Liabilities:				
Current liability	Commodity derivative liabilities	$ 4,201	$ (2,366)	$ 1,835
Long-term liability	Commodity derivative liabilities	1,280	(179)	1,101
Total liabilities		$ 5,481	$ (2,545)	$ 2,936

As of December 31, 2015				
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counterparty Netting**	**Net Carrying Value on Balance Sheet**
			(In thousands)	
Assets:				
Current asset	Commodity derivative assets	$ 48,260	$ —	$ 48,260
Long-term asset	Deferred charges and other long-term assets	16,274	—	16,274
Total assets		$ 64,534	$ —	$ 64,534
Liabilities:				
Current liability	Commodity derivative liabilities	$ —	$ —	$ —
Long-term liability	Commodity derivative liabilities	—	—	—
Total liabilities		$ —	$ —	$ —

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

Derivatives not designated as hedging instruments	**For the six months ended June 30, 2016**	**2015**
	(In thousands)	
Beginning fair value of commodity derivative instruments	$ 64,534	$ 37,471
Loss on oil derivative instruments	(12,615)	(3,696)
Gain (loss) on natural gas derivative instruments	(7,492)	4,716
Net cash received on settlements of oil derivative instruments	(18,766)	(22,413)
Net cash received on settlements of natural gas derivative instruments	(15,152)	(11,742)
Net change in fair value of commodity derivative instruments	(54,025)	(33,135)
Ending fair value of commodity derivative instruments	$ 10,509	$ 4,336

The Partnership had the following open derivative contracts for oil as of June 30, 2016:

Period and Type of Contract	Volume (Bbl)	Weighted Average (Per Bbl)	Range (Per Bbl) Low	Range (Per Bbl) High
Oil Swap Contracts:				
2016				
Second Quarter	183,000	$ 53.46	$ 33.60	$ 61.96
Third Quarter	525,000	54.62	34.41	62.53
Fourth Quarter	478,000	56.26	36.31	63.07
2017				
First Quarter	364,000	$ 62.69	$ 52.73	$ 63.65
Second Quarter	339,000	54.00	53.49	54.38

The Partnership had the following open derivative contracts for natural gas as of June 30, 2016:

Period and Type of Contract	Volume (MMBtu)	Weighted Average (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2016				
Third Quarter	7,320,000	$ 2.96	$ 2.23	$ 3.17
Fourth Quarter	6,570,000	3.12	2.29	3.41
2017				
First Quarter	5,660,000	$ 3.44	$ 3.08	$ 3.52
Second Quarter	5,310,000	3.12	2.85	3.18
Third Quarter	4,910,000	2.93	2.90	2.94
Fourth Quarter	4,610,000	3.06	2.92	3.21

The Partnership entered into the following derivative contracts for natural gas subsequent to June 30, 2016:

Period and Type of Contract	Volume (MMBtu)	Weighted Average (Per MMBtu)	Range (Per MMBtu) Low	Range (Per MMBtu) High
Natural Gas Swap Contracts:				
2016				
Third Quarter	240,000	$ 2.77	$ 2.77	$ 2.78
Fourth Quarter	360,000	3.00	2.81	3.23
2017				
First Quarter	510,000	$ 3.34	$ 3.30	$ 3.38
Second Quarter	510,000	3.05	3.03	3.07
Third Quarter	510,000	3.10	3.08	3.11
Fourth Quarter	410,000	3.17	3.10	3.29

NOTE 6—FAIR VALUE MEASUREMENT

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

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

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

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. There were no transfers into, or out of, the three levels of the fair value hierarchy for the six months ended June 30, 2016 or the year ended December 31, 2015.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership 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 5 – Derivatives and Financial Instruments for further discussion.

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

	Fair Value Measurements Using			Effect of Counterparty Netting	Total
	Level 1	Level 2	Level 3		
			(In thousands)		
As of June 30, 2016					
Financial Assets					
Commodity derivative instruments	$ —	$ 15,990	$ —	$ (2,545)	$ 13,445
Financial Liabilities					
Commodity derivative instruments	—	5,481	—	(2,545)	2,936
As of December 31, 2015					
Financial Assets					
Commodity derivative instruments	$ —	$ 64,534	$ —	$ —	$ 64,534
Financial Liabilities					
Commodity derivative instruments	—	—	—	—	—

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

The determination of the fair values of proved and unproved properties acquired in business combinations are 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. The Partnership has designated these measurements as Level 3.

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach when assessing for impairment. Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties.

The Partnership'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 June 30, 2016 or December 31, 2015.

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

	Fair Value Measurements Using			Net Book	
	Level 1	Level 2	Level 3	Value[1]	Impairment
			(In thousands)		
June 30, 2016					
Impaired oil and natural gas properties	$ —	$ —	$ 543	$ 1,222	$ 679
March 31, 2016					
Impaired oil and natural gas properties	$ —	$ —	$ 2,499	$ 8,595	$ 6,096
June 30, 2015					
Impaired oil and natural gas properties	$ —	$ —	$ 71,845	$ 190,207	$ 118,362
March 31, 2015					
Impaired oil and natural gas properties	$ —	$ —	$ 17,826	$ 31,293	$ 13,467

1 Amount represents net book value at the date of assessment.

The Partnership evaluates impairment of producing properties whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The Partnership compares the undiscounted projected future cash flows expected to the carrying amount to determine recoverability. When the carrying amount exceeds its estimated undiscounted future cash flows, the carrying amount is written down to its fair value, which is measured as the present value of the projected future cash flows of such properties. The factors used to determine fair value include estimates of economic reserves, future operating and development costs, future commodity prices, and a risk-adjusted discount rate. The Partnership's fair value assessment for recent acquisitions is included in Note 4 – Acquisitions.

The estimated carrying value of all debt as of June 30, 2016 and December 31, 2015 approximated the fair value due to variable market rates of interest. These fair values, which are Level 3 measurements, were estimated based on the Partnership's incremental borrowing rates for similar types of borrowing arrangements, when quoted market prices were not available. The estimated fair values of the Partnership's financial instruments are not necessarily indicative of the amounts that would be realized in a current market exchange. The carrying value of receivables and payables approximate fair value due to the short-term nature of the instruments.

NOTE 7—CREDIT FACILITY

The Partnership maintains a senior secured revolving credit agreement (the "Senior Line of Credit"). The Senior Line of Credit has a maximum credit amount of $1.0 billion. On October 28, 2015, the Senior Line of Credit was amended to extend the term of the agreement from February 3, 2017 to February 4, 2019. The amount of the borrowing base is derived from the value of the Partnership's oil and natural gas properties determined by the lender syndicate using pricing assumptions that often differ from the current market for future prices. The Partnership's semi-annual borrowing base redetermination process resulted in a decrease of the borrowing base from $550.0 million to $450.0 million, effective April 15, 2016. The next borrowing base redetermination is scheduled for October 2016. Drawings on the Senior Line of Credit are used for the acquisition of oil and natural gas properties and for other general business purposes.

Borrowings under the Senior Line of Credit bear interest at LIBOR plus a margin between 1.50% and 2.50%, or the Prime rate plus a margin between 0.50% and 1.50%, with the margin depending on the borrowing base utilization percentage of the loan, as detailed in the table below. 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.

	Borrowing Base Utilization				
Borrowing type	**<25%**	**≥25% <50%**	**≥50% <75%**	**≥75% <90%**	**≥90%**
Eurodollar Margin	1.50%	1.75%	2.00%	2.25%	2.50%
Base Rate Margin	0.50%	0.75%	1.00%	1.25%	1.50%

The weighted-average interest rate of the Senior Line of Credit was 2.45% and 1.92% as of June 30, 2016 and December 31, 2015, 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 0.500% per annum if the borrowing base utilization percentage is equal to or greater than 50%. The Senior Line of Credit is secured by substantially all of the Partnership's producing oil and natural gas assets.

The Senior Line of Credit contains various limitations on future borrowings, leases, hedging, and sales of assets. Additionally, the Senior Line of Credit requires the Partnership to maintain a current ratio of not less than 1.0:1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5:1.0. As of June 30, 2016, the Partnership was in compliance with all financial covenants for the Senior Line of Credit.

The aggregate principal balance outstanding was $285.0 million and $66.0 million at June 30, 2016 and December 31, 2015, respectively. The unused portion of the available borrowings under the Senior Line of Credit was $165.0 million and $484.0 million at June 30, 2016 and December 31, 2015, respectively.

NOTE 8—COMMITMENTS AND CONTINGENCIES

Environmental Matters

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

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

Litigation

From time to time, the Partnership is involved in legal actions and claims arising in the ordinary course of business. The Partnership believes existing claims as of June 30, 2016 will be resolved without material adverse effect on the Partnership's financial condition or operations.

NOTE 9—INCENTIVE COMPENSATION

On January 12, 2016, each non-employee director on the Board of Directors of the Partnership's general partner (the "Board") was granted 12,368 fully vested common units for service during 2015. On February 19, 2016, the Compensation Committee of the Board approved a grant of awards to each of the Partnership's executive officers and certain other employees. These awards consisted of restricted common units and restricted performance units (in the form of phantom units) with distribution equivalent rights. The grants included 717,654 restricted common units subject to limitations on transferability, customary forfeiture provisions, and service-based graded vesting requirements through January 7, 2019. The holders of restricted common unit awards have all of the rights of a common unitholder, including non-forfeitable distribution rights with respect to their restricted common units. The grant-date fair value of these awards, net of estimated forfeitures, is recognized ratably using the straight-line attribution method. The Compensation Committee of the Board also approved a grant of 717,654 restricted performance units that are subject to both performance-based and service-based vesting provisions. The number of common units issued to a recipient upon vesting of a restricted performance unit will be calculated based on performance against certain metrics that relate to the Partnership's average performance over each calendar year during the performance period commencing January 1, 2016. The target number of common units subject to each restricted performance unit is one; however, based on the achievement of performance criteria, the number of common units that may be received in settlement of each restricted performance unit can range from zero to two times the target number. The restricted performance units are eligible to become earned at the end of the performance period on December 31, 2018. Compensation expense related to the restricted performance unit awards is determined by multiplying the number of common units underlying such awards that, based on the Partnership's estimate, are likely to vest, by the grant-date fair value and recognized using the accelerated attribution method. Distribution equivalent rights for the restricted performance unit awards that are expected to vest are charged to partners' capital. The Compensation Committee of the Board also approved the dollar-value targets for performance-based short-term incentive compensation for executive officers of the Partnership and certain other employees. The Partnership expects to ultimately settle the authorized awards at the end of the performance period in common units of the Partnership.

On April 25, 2016, the Compensation Committee of the Board approved a resolution to change the settlement feature of certain employee long-term incentive compensation plans from cash to equity. As a result of the modification, $10.1 million of cash-settled liabilities were reclassified to equity-settled liabilities during the current quarter and the remaining unamortized expense of the awards will be amortized into equity-settled liabilities.

The table below summarizes incentive compensation expense recorded in general and administrative expenses in the consolidated statements of operations for the three months and six months ended June 30, 2016 and 2015, respectively.

Incentive compensation expense	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
	(In thousands)		(In thousands)	
Cash—long-term incentive plan	$ 560	$ 4,029	$ 2,410	$ 7,480
Equity-based compensation—restricted common and subordinated units	3,190	2,668	5,933	3,950
Equity-based compensation—restricted performance units	5,426	1,260	8,039	1,260
Board of Directors incentive plan	476	1,671	957	2,152
Total incentive compensation expense	$ 9,652	$ 9,628	$ 17,339	$ 14,842

NOTE 10—REDEEMABLE PREFERRED UNITS

The Partnership had 52,691 and 77,216 preferred units outstanding with a carrying value of $54.0 million and $79.2 million as of June 30, 2016 and December 31, 2015, respectively. The aforementioned amounts included accrued distributions of $1.3 million and $1.9 million as of June 30, 2016 and December 31, 2015, respectively. The redeemable preferred units are classified as mezzanine equity on the consolidated balance sheets since redemption is outside the control of the Partnership. The preferred units are entitled to an annual distribution of 10% of the funded capital of the preferred units, payable on a quarterly basis in arrears.

The preferred units are convertible into common and subordinated units at any time at the option of the preferred unitholders. The preferred units have an adjusted conversion price of $14.2683 and an adjusted conversion rate of 30.3431 common units and 39.7427 subordinated units per preferred unit, which reflects the reverse split described in Note 1 – Business and Basis of Presentation and the capital restructuring related to the IPO. The preferred unitholders can elect to have the Partnership redeem up to 25% per year of their initial balance of preferred units at face value, plus any accrued and unpaid distributions, as of December 31 of each year from 2014 to 2017. The Partnership 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 as of each December 31. Any amount of a given year's 25% of preferred units not redeemed as of December 31 shall automatically convert to common and subordinated units in the following year. For the six months ended June 30, 2016, 18,461 preferred units were redeemed for $19.0 million, including accrued unpaid yield, and are included in accrued liabilities on the consolidated balance sheet. For the six months ended June 30, 2016, 6,064 preferred units totaling $6.1 million were converted into 184,006 common units and 240,986 subordinated units as a result of the mandatory conversion subsequent to December 31, 2015. For the year ended December 31, 2015, 39,240 preferred units totaling $39.2 million were converted into the equivalent of 1,190,664 common units and 1,559,502 subordinated units on an adjusted basis.

NOTE 11—EARNINGS PER UNIT

The Partnership applies the two-class method for purposes of calculating earnings per unit ("EPU"). The holders of the Partnership's restricted common and subordinated units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common and subordinated units are included in the calculation of basic earnings per unit. For the periods presented, the amount of earnings allocated to these participating units was not material. Net income (loss) attributable to the Partnership is allocated to the Partnership's general partner and the common and subordinated unitholders in proportion to their pro rata ownership after giving effect to distributions, if any, declared during the period. The redeemable preferred units could be converted into 1.6 million common units and 2.1 million subordinated units as of June 30, 2016. At June 30, 2016, if the redeemable preferred units were converted to common and subordinated units, the effect would be anti-dilutive. Therefore, the redeemable preferred units are not included in the diluted EPU calculation. The Partnership's restricted performance unit awards are contingently issuable units that are considered in the calculation of diluted EPU. The Partnership assesses the number of units that would be issuable, if any, under the terms of the arrangement if the end of the reporting period were the end of the contingency period. For the six months ended June 30, 2016, there were 125,487 common units related to the Partnership's restricted performance unit awards included in the calculation of diluted EPU.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2016	2015	2016	2015
	(In thousands, except per unit amounts)		(In thousands, except per unit amounts)	
Net loss	$ (20,810)	$ (122,766)	$ (10,061)	$ (105,467)
Net (income) loss attributable to Predecessor	—	16,849	—	(450)
Net loss attributable to noncontrolling interests subsequent to initial public offering	9	140	7	140
Distributions on redeemable preferred units subsequent to initial public offering	(1,310)	(1,810)	(3,114)	(1,810)
Net loss attributable to the general partner and common and subordinated units subsequent to initial public offering	$ (22,111)	$ (107,587)	$ (13,168)	$ (107,587)
Allocation of net income (loss) subsequent to initial public offering attributable to:				
General partner interest	$ —	$ —	$ —	$ —
Common units	(7,445)	(54,109)	862	(54,109)
Subordinated units	(14,666)	(53,478)	(14,030)	(53,478)
	$ (22,111)	$ (107,587)	$ (13,168)	$ (107,587)
Net income (loss) attributable to limited partners per common and subordinated units:				
Per common unit (basic)	$ (0.08)	$ (0.56)	$ 0.01	$ (0.56)
Weighted average common units outstanding (basic)	96,356	96,178	96,418	96,178
Per subordinated unit (basic)	$ (0.15)	$ (0.56)	$ (0.15)	$ (0.56)
Weighted average subordinated units outstanding (basic)	95,189	95,057	95,092	95,057
Per common unit (diluted)	$ (0.08)	$ (0.56)	$ 0.01	$ (0.56)
Weighted average common units outstanding (diluted)	96,418	96,178	96,481	96,178
Per subordinated unit (diluted)	$ (0.15)	$ (0.56)	$ (0.15)	$ (0.56)
Weighted average subordinated units outstanding (diluted)	95,092	95,057	95,092	95,057

NOTE 12—SUBSEQUENT EVENTS

On August 8, 2016, the Board approved a distribution for the period April 1, 2016 to June 30, 2016 of $0.2875 per common unit and $0.18375 per subordinated unit. Distributions will be payable on August 25, 2016 to unitholders of record at the close of business on August 18, 2016.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q, as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 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 "Partnership," "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;
- future cash flows and liquidity, including our ability to generate sufficient cash to pay quarterly distributions;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;

- the ability of our operators to keep pace with technological advancements; 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 Annual Report on Form 10-K.

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 terms on those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working-interest basis in low-risk development-drilling opportunities on our interests. 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.

On May 1, 2015 our common units began trading on the New York Stock Exchange under the symbol "BSM." 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.

As of June 30, 2016, our mineral and royalty interests were located in 41 states and 61 onshore basins in the continental United States. These non-cost-bearing interests include ownership in over 45,000 producing wells. We also own non-operated working interests, largely on our mineral and royalty 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

Common Unit Repurchase Program

On March 4, 2016, the Board of Directors of our general partner (the "Board") authorized the repurchase of up to $50.0 million in common units over the next six months. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be repurchased when we might otherwise be precluded from doing so under insider trading laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion. We will periodically report the number of common units repurchased. The repurchase program will be funded from our cash on hand or available revolving credit facility. Any repurchased common units will be cancelled.

Acquisitions

On January 8, 2016, we acquired mineral and royalty interests in the Permian Basin for $10.0 million.

On June 15, 2016, we acquired an oil and natural gas mineral package primarily located in Weld County, Colorado for $34.0 million.

On June 17, 2016, we acquired a diverse oil and natural gas mineral asset package from Freeport-McMoRan Oil and Gas Inc. and certain of its affiliates for $87.9 million.

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. Recently, oil and natural gas prices have remained significantly below prices seen over the past five years. The Energy Information Administration ("EIA") expects the oil market to reach balance in 2017, although, daily and even monthly price variations could be significant as economic and geopolitical events affect market participants' expectations of oil market balances. Significant outages of global oil supply contributed to rising oil prices in early June; however, concerns over future economic growth related to the United Kingdom's June 23 vote to exit the European Union and the easing of supply disruptions in Canada resulted in falling oil prices in late June. The recent increase in natural gas prices is a result of declines in domestic production and higher demand for natural gas to fuel electricity generation. The EIA projects that increases in natural gas prices will continue through 2016 and will contribute to a reversal in production declines during the second half of the year. During the six months ended June 30, 2016, the West Texas Intermediate ("WTI") spot price reached a low of $26.19 per Bbl on February 11, 2016, but rebounded to a high of $51.23 per Bbl on June 8, 2016. During the six months ended June 30, 2016, Henry Hub spot natural gas prices ranged from a low of $1.49 per MMBtu on March 4, 2016 to a high of $2.94 per MMBtu on June 30, 2016. To manage the variability in cash flows associated with the projected sale of our oil and natural gas production, we use various derivative instruments, which have recently consisted of fixed-price swap contracts.

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

	2015		2016	
Benchmark Prices	**First Quarter**	**Second Quarter**	**First Quarter**	**Second Quarter**
WTI spot oil price ($/Bbl)	$ 47.72	$ 59.48	$ 36.94	$ 48.27
Henry Hub spot natural gas ($/MMBtu)	$ 2.65	$ 2.80	$ 1.98	$ 2.94

Source: EIA

Rig Count

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

The following table shows the rig count at the close of each quarter for the periods presented:

	2015		2016	
U.S. Rotary Rig Count	**First Quarter**	**Second Quarter**	**First Quarter**	**Second Quarter**
Oil	813	628	372	330
Natural gas	233	228	92	90
Other	2	3	—	1
Total	1,048	859	464	421

Source: Baker Hughes Incorporated

Natural Gas Storage

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

Historically, natural gas supply and demand fluctuates on a seasonal basis. From April to October, when the weather is warmer and natural gas demand is lower, natural gas storage levels generally increase. From November to March, storage levels typically decline as utility companies draw natural gas from storage to meet increased heating demand due to colder weather. In order to maintain sufficient storage levels for increased seasonal demand, a portion of natural gas production during the summer months must be used for storage injection. The portion of production used for storage varies from year to year depending on the demand from the previous winter and the demand for electricity used for cooling during the summer months. The EIA forecasts natural gas inventories to be 4,022 Bcf at the end of October 2016, which would be the highest level on record for that time of year.

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

Region	2015 First Quarter	2015 Second Quarter	2016 First Quarter	2016 Second Quarter
	(Bcf)			
East	255	552	439	632
Midwest	261	546	555	742
Mountain	114	155	147	198
Pacific	269	333	262	315
South Central	562	993	1,065	1,253
Total	1,461	2,579	2,468	3,140

Source: EIA

How We Evaluate Our Operations

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

- volumes of oil and natural gas produced;
- commodity prices including the effect of derivative instruments; and
- EBITDA, Adjusted EBITDA, and cash available for distribution.

Volumes of Oil and Natural Gas Produced

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

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

The prices we receive for oil, natural gas, and natural gas liquids ("NGLs") vary by geographical area. The relative prices of these products are determined by the factors affecting global and regional supply and demand dynamics, such as economic conditions, production levels, availability of transportation, weather cycles, and other factors. In addition, realized prices are influenced by product quality and proximity to consuming and refining markets. Any differences between realized prices and 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 substantial majority of our oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. NYMEX light sweet crude oil, commonly referred to as WTI, is the prevailing domestic oil pricing index. The majority of our oil production is priced at the prevailing market price with the final realized price affected by both quality and location differentials.

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

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

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

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

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

Hedging

We enter into derivative instruments to partially mitigate the impact of commodity price volatility on our cash generated from operations. From time to time, such instruments may include fixed-price swaps, fixed-price contracts, costless collars, and other contractual arrangements. We generally employ a "rolling hedge" strategy whereby we hedge a significant portion of our proved developed producing reserves 18 to 24 months into the future. The impact of these derivative instruments could affect the amount of revenue we ultimately realize. Since 2015, we have only 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; conversely, 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 fixed-price swap contracts in the future to mitigate the impact of price fluctuations. If commodity prices decline in the future, our hedging contracts will partially mitigate the effect of lower prices on our future revenue.

Our open oil and natural gas derivative contracts as of June 30, 2016 and the date of this filing are detailed in Note 5 – Derivatives and Financial Instruments to our unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q. Our credit 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. We do not enter into derivative instruments for speculative purposes. Including derivative contracts entered into subsequent to June 30, 2016, we have hedged 99.2% and 43.7% of our available oil and condensate hedge volumes and 98.5% and 98.4% of our available natural gas hedge volumes for the remainder of 2016 and 2017, 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 adjusted for impairment of oil and natural gas properties, accretion of ARO, unrealized gains and losses on commodity 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 should not be considered an alternative to, or more meaningful than, net income (loss), income (loss) from operations, cash flows from operating activities, or any other measure of financial performance presented in accordance with 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 (loss), 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 (loss), the most directly comparable GAAP financial measure, for the periods indicated.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(Unaudited) (In thousands)			
Net loss	$ (20,810)	$ (122,766)	$ (10,061)	$ (105,467)
Adjustments to reconcile to Adjusted EBITDA:				
Add:				
Depreciation, depletion and amortization	29,202	32,235	50,923	60,126
Interest expense	1,443	1,715	2,491	4,660
EBITDA	9,835	(88,816)	43,353	(40,681)
Add:				
Impairment of oil and natural gas properties	679	118,362	6,775	131,829
Accretion of asset retirement obligations	200	269	474	540
Equity-based compensation[1]	19,239	6,119	25,139	7,362
Unrealized loss on commodity derivative instruments	44,070	35,332	54,025	33,135
Adjusted EBITDA	74,023	71,266	129,766	132,185
Adjustments to reconcile to cash generated from operations:				
Add:				
Incremental general and administrative related to initial public offering	—	452	—	679
Less:				
Change in deferred revenue	424	(386)	221	(490)
Cash interest expense	(1,246)	(1,474)	(2,097)	(4,178)
Gain on sales of assets, net	(92)	(17)	(4,772)	(24)
Estimated replacement capital expenditures[2]	(3,750)	—	(3,750)	—
Cash generated from operations	69,359	69,841	119,368	128,172
Less:				
Cash paid to noncontrolling interests	(21)	(70)	(54)	(122)
Redeemable preferred unit distributions	(1,310)	(2,941)	(3,114)	(5,850)
Cash generated from operations available for distribution on common and subordinated units and reinvestment in our business	$ 68,028	$ 66,830	$ 116,200	$ 122,200

[1] On April 25, 2016, the Compensation Committee of the Board approved a resolution to change the settlement feature of certain employee long-term incentive compensation plans from cash to equity. As a result of the modification, $10.1 million of cash-settled liabilities were reclassified to equity-settled liabilities during the current quarter.

[2] On August 3, 2016, the Board established a replacement capital expenditure estimate of $15.0 million for the period of April 1, 2016 to March 31, 2017. There was no established estimate of replacement capital expenditure prior to this period.

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 higher general and administrative expenses than in prior periods 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 fees; Sarbanes-Oxley Act compliance; New York Stock Exchange listing fees; 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 for periods prior to our IPO.

Results of Operations

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

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

	Three Months Ended June 30,			
	2016	2015	Variance	
	(Unaudited) (Dollars in thousands, except for realized prices and per BOE data)			
Production:				
Oil and condensate (MBbls)[1]	947	905	42	4.6%
Natural gas (MMcf)[1]	11,558	10,621	937	8.8%
Equivalents (MBoe)	2,873	2,675	198	7.4%
Revenue:				
Oil and condensate sales	$ 34,553	$ 46,293	$ (11,740)	(25.4%)
Natural gas and natural gas liquids sales	21,607	28,968	(7,361)	(25.4%)
Loss on commodity derivative instruments	(30,733)	(18,627)	(12,106)	65.0%
Lease bonus and other income	15,142	8,169	6,973	85.4%
Total revenue	$ 40,569	$ 64,803	$ (24,234)	(37.4%)
Realized prices:				
Oil and condensate ($/Bbl)	$ 36.49	$ 51.15	$ (14.66)	(28.7%)
Natural gas ($/Mcf)[1]	1.87	2.73	(0.86)	(31.5%)
Equivalents ($/Boe)	$ 19.55	$ 28.13	$ (8.58)	(30.5%)
Operating expenses:				
Lease operating expense	$ 4,283	$ 5,483	$ (1,200)	(21.9%)
Production costs and ad valorem taxes	7,012	9,819	(2,807)	(28.6%)
Exploration expense	629	158	471	298.1%
Depreciation, depletion, and amortization	29,202	32,235	(3,033)	(9.4%)
Impairment of oil and natural gas properties	679	118,362	(117,683)	(99.4%)
General and administrative	18,134	19,718	(1,584)	(8.0%)
Other expense:				
Interest expense	$ 1,443	$ 1,715	$ (272)	(15.9%)
Per Boe:				
Lease operating expense	$ 1.49	$ 2.05	$ (0.56)	(27.3%)
Lease operating expense (per working interest Boe)	4.66	7.18	(2.52)	(35.1%)
Production costs and ad valorem taxes	2.44	3.67	(1.23)	(33.5%)
Depreciation, depletion, and amortization	10.16	12.05	(1.89)	(15.7%)
General and administrative	6.31	7.37	(1.06)	(14.4%)

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

Revenue

Total revenue for the quarter ended June 30, 2016 decreased compared to the quarter ended June 30, 2015. Production for the quarter ended June 30, 2016 averaged 31.6 MBoe per day, an increase of 2.2 MBoe per day compared to the corresponding period in 2015. The decrease in total revenues is primarily due to lower realized commodity prices, the impact of which totaled $23.8 million, and an increase in losses on commodity derivative instruments as compared to the corresponding period in 2015. Increased production volumes and higher lease bonus partially offset the overall decrease in total revenue.

Oil and condensate sales. Oil and condensate sales during the period were lower than the second quarter of 2015 primarily due to lower realized prices. Our total oil and condensate production was higher than the second quarter of 2015, but the increased production was more than offset by the decline in realized prices. Our mineral-and-royalty-interest oil and condensate volumes accounted for 79.3% and 78.4% of total oil and condensate volumes for the quarters ended June 30, 2016 and 2015, respectively. Our mineral-and-royalty-interest oil and condensate volumes increased 5.9% in the second quarter of 2016 relative to the corresponding period in 2015, primarily driven by production increases from new wells in the Bakken/Three Forks and Wolfcamp plays. Our working-interest oil and condensate volumes decreased by 0.1% during the second quarter of 2016 versus the same period in 2015 to 2.1 MBbls per day.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased for the quarter ended June 30, 2016 as compared to the same period for 2015. Lower realized natural gas and NGL prices for the quarter ended June 30, 2016 versus the corresponding period in 2015 were primarily responsible for the decline in our natural gas and NGL revenues. The decline in pricing was partially offset by increased production, primarily related to new wells in the Haynesville play. Mineral-and-royalty-interest production accounted for 62.5% and 67.9% of our natural gas volumes for the quarters ended June 30, 2016 and 2015, respectively.

Loss on commodity derivative instruments. During the second quarter of 2016, we recognized $15.5 million of losses from oil commodity contracts, which included cash received of $6.2 million, compared to recognized losses of $16.7 million in the same period of 2015. During the second quarter of 2016, we recognized $15.2 million of losses from natural gas commodity contracts, which included cash received of $7.1 million, compared to recognized losses of $1.9 million in the same period of 2015.

Lease bonus and other income. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. In the second quarter of 2016, we successfully closed several significant lease transactions. Specifically, these transactions were in the Woodbine play in East Texas, the Wolfcamp and Bone Springs plays in West Texas, and the Haynesville play in Louisiana.

Operating and Other Expenses

Lease operating expense. Lease operating expense includes normally recurring expenses associated with our non-operated working interests necessary to produce hydrocarbons from our oil and natural gas wells, as well as certain nonrecurring expenses, such as well repairs. Lease operating expense decreased for the quarter ended June 30, 2016 as compared to the same period in 2015, primarily due to lower costs associated with workover and other service-related costs and a higher percentage of working-interest volumes being produced from gas wells.

Production costs and ad valorem taxes. Production taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the regulations of the states where the production originates, these taxes may be based on a percentage of the realized value or a fixed amount per production unit. This category also includes the costs to process and transport our production to applicable sales points. Ad valorem taxes are jurisdictional taxes levied on the value of oil and natural gas minerals and reserves. Rates, methods of calculating property values, and timing of payments vary between taxing authorities. For the quarter ended June 30, 2016, production costs and ad valorem taxes decreased from the quarter ended June 30, 2015, generally as a result of lower realized prices and estimated mineral reserve valuations.

Exploration expense. Exploration expense typically consists of dry-hole expenses and geological and geophysical costs, including seismic costs, and is expensed as incurred under the successful efforts method of accounting. Exploration expense increased for the three months ended June 30, 2016 as compared to the same period in 2015, primarily due to costs incurred to acquire 3-D seismic information.

Depreciation, depletion, and amortization. Depletion is an estimate of the amount of cost basis of oil and natural gas properties attributable to the volume of hydrocarbons extracted during a period, calculated on a units-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We adjust our depletion rates semi-annually based upon mid-year and year-end reserve reports, except when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization decreased for the quarter ended June 30, 2016 as compared to the same period in 2015, primarily due to the impact of a reduced cost basis resulting from impairment charges recorded during the prior twelve months. The impact of higher production rates and costs associated with new reserve additions partially offset the overall decrease in depreciation depletion, and amortization.

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 activity, unproved leasehold, and mineral interests to identify impairments. Impairments totaled $0.7 million for the quarter ended June 30, 2016 primarily due to drilling costs in the Mississippian play exceeding our future expected realizable net cash flows. Impairments for the second quarter of 2015 were primarily due to changes in reserve values resulting from declines in future expected realizable net cash flows as a result of lower commodity prices.

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 employee salaries and related benefits, office expenses, and fees for professional services. For the quarter ended June 30, 2016, general and administrative expenses decreased as compared to the same period in 2015. In 2016, personnel costs and costs attributable to our long-term incentive plans were $1.6 million lower than in the corresponding prior period in 2015.

Interest expense. Interest expense decreased due to lower borrowings under our credit facility. Average outstanding borrowings during the second quarter of 2016 were lower than the second quarter of 2015 due to mid-year 2015 repayments towards our credit facility using proceeds received from our IPO.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

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

	Six Months Ended June 30,			
	2016	2015	Variance	
	(Dollars in thousands, except for realized prices and per BOE data)			
Production:				
Oil and condensate (MBbls)[1]	1,833	1,732	101	5.8%
Natural gas (MMcf)[1]	22,807	21,406	1,401	6.5%
Equivalents (MBoe)	5,634	5,300	334	6.3%
Revenue:				
Oil and condensate sales	$ 61,801	$ 82,456	$ (20,655)	(25.0%)
Natural gas and natural gas liquids sales	46,719	60,608	(13,889)	(22.9%)
Gain (loss) on commodity derivative instruments	(20,107)	1,020	(21,127)	NM
Lease bonus and other income	16,537	11,780	4,757	40.4%
Total revenue	$ 104,950	$ 155,864	$ (50,914)	(32.7%)
Realized prices:				
Oil and condensate ($/Bbl)	$ 33.72	$ 47.61	$ (13.89)	(29.2%)
Natural gas ($/Mcf)[1]	2.05	2.83	(0.78)	(27.6%)
Equivalents ($/Boe)	$ 19.26	$ 26.99	$ (7.73)	(28.6%)
Operating expenses:				
Lease operating expense	$ 9,172	$ 11,616	$ (2,444)	(21.0%)
Production costs and ad valorem taxes	14,074	18,075	(4,001)	(22.1%)
Exploration expense	637	197	440	223.4%
Depreciation, depletion, and amortization	50,923	60,126	(9,203)	(15.3%)
Impairment of oil and natural gas properties	6,775	131,829	(125,054)	(94.9%)
General and administrative	35,535	34,536	999	2.9%
Other expense:				
Interest expense	$ 2,491	$ 4,660	$ (2,169)	(46.5%)
Per Boe:				
Lease operating expense	$ 1.63	$ 2.19	$ (0.56)	(25.6%)
Lease operating expense (per working interest Boe)	5.02	7.07	(2.05)	(29.0%)
Production costs and ad valorem taxes	2.50	3.41	(0.91)	(26.7%)
Depreciation, depletion, and amortization	9.04	11.34	(2.30)	(20.3%)
General and administrative	6.31	6.52	(0.21)	(3.2%)

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

Revenue

Total revenues for the six months ended June 30, 2016 decreased compared to the six months ended June 30, 2015. Production for the six months ended June 30, 2016 averaged 31.0 MBoe per day, an increase of 1.7 MBoe per day, or 5.7%, compared to the corresponding period in 2015. The decrease in total revenues from the corresponding prior period is primarily due to the effect of lower realized commodity prices, the impact of which totaled $43.3 million, and a $21.1 million difference in the impact of commodity derivative instruments, partially offset by the impact of $4.8 million higher lease bonus and $8.8 million related to increased production volumes.

Oil and condensate sales. Oil and condensate sales during for the six months ended June 30, 2016 were lower than the corresponding period in 2015 primarily due to lower realized prices. Oil and condensate production for the six months ended June 30, 2016 was higher than in the six months ended June 30, 2015, but that was more than offset by a decline in realized prices. Our mineral-and-royalty-interest oil and condensate volumes accounted for 78.9% and 77.3% of total oil and condensate volumes for the six months ended June 30, 2016 and 2015, respectively. Our mineral-and-royalty-interest oil and condensate volumes increased 8.1% for the six months ended June 30, 2016 relative to the corresponding period in 2015, primarily driven by production increases from new wells in the Bakken/Three Forks and Wolfcamp plays. Our working-interest oil and condensate volumes decreased by 2.0% to 2.1 MBbls per day during the six months ended June 30, 2016 versus the same period in 2015 primarily due to normal production declines in the Bakken/Three Forks play.

Natural gas and natural gas liquids sales. Natural gas and NGL sales decreased for the six months ended June 30, 2016 as compared to the same period for 2015. A decline in the realized natural gas and NGL price for the six months ended June 30, 2016 versus the corresponding period in 2015 was primarily responsible for the decline in our natural gas and NGL revenues. The unfavorable price variance was partially offset by a 6.5% increase in production volumes. This production increase was primarily generated by production from new wells in the Haynesville/Bossier and Wilcox plays. Mineral-and-royalty-interest production accounted for 62.0% and 65.0% of our natural gas volumes for the six months ended June 30, 2016 and 2015, respectively.

Gain (loss) on commodity derivative instruments. During the six months ended June 30, 2016, we recognized $12.6 million of losses from oil commodity contracts, which included $18.8 million in cash received, compared to a recognized loss of $3.7 million in the same period of 2015. During the first six months of 2016, we recognized $7.5 million of losses from natural gas commodity contracts, which included $15.2 million of cash received, compared to a recognized gain of $4.7 million in the same period of 2015.

Lease bonus and other income. Lease bonus and other income increased for the six months ended June 30, 2016 as compared to the same period in 2015. In the first six months of 2016, we successfully closed several significant lease transactions in Jasper, Tyler, Pecos and Newton counties of Texas and in Red River parish in Louisiana.

Operating and Other Expenses

Lease operating expense. Lease operating expense decreased for the six months ended June 30, 2016 as compared to the same period in 2015, primarily due to lower costs associated with workover and other service-related costs and a higher percentage of working-interest volumes being produced from gas wells.

Production costs and ad valorem taxes. For the six months ended June 30, 2016, production costs and ad valorem taxes decreased from the six months ended June 30, 2015, generally as a result of lower realized prices and estimated mineral reserve valuations.

Exploration expense. Exploration expense increased for the six months ended June 30, 2016 as compared to the same period in 2015, primarily due to costs incurred to acquire 3-D seismic information.

Depreciation, depletion, and amortization. Depreciation, depletion, and amortization decreased for the six months ended June 30, 2016 as compared to the same period in 2015, primarily due to the impact of a reduced cost basis resulting from impairment charges recorded during the prior twelve months. The impact of higher production rates and costs associated with new reserve additions partially offset the overall decrease in depreciation, depletion, and amortization.

Impairment of oil and natural gas properties. Impairments totaled $6.8 million for the six months ended June 30, 2016 primarily due to changes in reserve values resulting from declines in future expected realized net cash flows.

General and administrative. For the six months ended June 30, 2016, general and administrative expenses increased as compared to the same period in 2015. During the six months ended June 30, 2016, personnel costs and costs attributable to our long-term incentive plans were $0.5 million higher than in the corresponding prior period of 2015.

Interest expense. Interest expense decreased due to lower average outstanding borrowings under our credit facility. Average outstanding borrowings during the first six months of 2016 were lower than the six months ended June 30, 2015, primarily due to payments made towards the outstanding balance of our credit facility subsequent to our IPO.

Liquidity and Capital Resources

Overview

Our primary sources of liquidity are cash generated from operations, borrowings under our credit facility, and proceeds from the issuance of equity and debt. Our primary uses of cash are for distributions to our unitholders and for investing in our business, specifically the acquisition of mineral and royalty interests and our selective participation on a nonoperated-working-interest basis in 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. 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. Our minimum quarterly distribution provides the common unitholders a specified priority right to distributions over the subordinated unitholders. The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time.

We intend to finance our future acquisitions and working-interest capital needs with cash generated from operations, borrowings from our credit facility, and proceeds from any future issuances of equity and debt. 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. The board of directors of our general partner established a replacement capital expenditure estimate of $15.0 million for the period of April 1, 2016 to March 31, 2017.

Cash Flows

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

	Six Months Ended June 30,	
	2016	2015
	(Unaudited) (In thousands)	
Cash flows provided by operating activities	$ 83,544	$ 144,084
Cash flows used in investing activities	(172,878)	(42,015)
Cash flows provided by (used in) financing activities	85,871	(110,824)

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Operating Activities. Our operating cash flows are dependent, in large part, on our production, realized commodity prices, lease bonus revenue, and operating expenses. Our cash flows from operations decreased from $144.1 million for the six months ended June 30, 2015 to $83.5 million for the six months ended June 30, 2016. The decrease was primarily due to lower cash collections of $55.4 million related to lower oil and natural gas sales and changes in working capital as compared to the corresponding period in 2015.

Investing Activities. Net cash used in investing activities increased by $130.9 million in the first six months of 2016 as compared to the corresponding period in 2015 due to four acquisitions that were closed during the first six months of 2016 and higher capital expenditures for our working interest properties.

Financing Activities. For the six months ended June 30, 2016, we generated cash from financing activities as we increased our borrowings under our senior line of credit and lowered distributions as compared to the corresponding period in 2015.

Capital Expenditures

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

Our 2016 drilling expenditures are expected to be between $65.0 million and $70.0 million. We expect to invest between $55.0 million and $60.0 million in the Haynesville/Bossier play with the remainder expected to be spent in the Bakken/Three Forks, Wolfcamp, and Wilcox plays. During the six months ended June 30, 2016, we incurred $33.2 million related to drilling and completion costs and $1.1 million related to prospect leasehold acreage, primarily in the aforementioned plays. We also spent $136.3 million related to four acquisitions in the current period as well as a deposit for a second closing planned for the third quarter of 2016 and a final holdback payment from an acquisition in 2015. See Note 4 – Acquisitions for further discussion.

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 lenders' estimated value of our oil and natural gas properties. On October 28, 2015, the third amended and restated credit facility was further amended to extend the term of the agreement from February 3, 2017 to February 4, 2019. 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 regular, semi-annual borrowing base redetermination process resulted in a decrease of the borrowing base from $550.0 million to $450.0 million, effective April 15, 2016. Our next borrowing base redetermination is scheduled for October 2016. As of June 30, 2016, we had outstanding borrowings of $285.0 million at a weighted-average interest rate of 2.45%.

The borrowing base under the third amended and restated credit agreement is redetermined semi-annually, typically on or around 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 to increase our existing borrowing base, and by two-thirds of the lenders to maintain or decrease 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 facility 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%, or 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 third amended and restated credit 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, as well as 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 a modified current ratio 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 third amended and restated 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 June 30, 2016, we were in compliance with all debt covenants.

Contractual Obligations

As of June 30, 2016, there have been no material changes to our contractual obligations previously disclosed in our 2015 Annual Report on Form 10-K.

Off-Balance Sheet Arrangements

As of June 30, 2016, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

As of June 30, 2016, there have been no significant changes to our critical accounting policies and related estimates previously disclosed in our 2015 Annual Report on Form 10-K.

New and Revised Financial Accounting Standards

The effects of new accounting pronouncements are discussed in the notes to our unaudited 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, natural gas, and natural gas liquids produced by our operators. Realized prices are primarily driven by the prevailing global prices for oil and prices for natural gas and NGLs in the United States. Prices for oil, natural gas, and natural gas liquids have been volatile 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 use commodity derivative instruments to reduce our exposure to price volatility of oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settle monthly in cash based on a designated floating price. The designated floating price has been based off the NYMEX benchmark for oil and natural gas. We have not designated any of our contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in net income in the period of the change. See Note 5 – Derivatives and Financial Instruments and Note 6 – Fair Value Measurement to the unaudited consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q for additional information.

Commodity prices have declined in recent years. To estimate the effect lower prices would have on our reserves, we applied a 10% discount to the SEC commodity pricing for the twelve months ended June 30, 2016. Applying this discount results in an approximate 3% reduction of proved reserve volumes as compared to the undiscounted June 30, 2016 SEC pricing scenario.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require our counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. This evaluation includes reviewing a counterparty's credit rating and latest financial information. As of June 30, 2016, we had ten counterparties, all of which are rated Baa2 or better by Moody's. Seven 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 operators to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit risk associated with our operators and customers is acceptable.

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness. As of June 30, 2016, we had $285.0 million of outstanding borrowings under our credit facility, bearing interest at a weighted-average interest rate of 2.45%. 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 $1.4 million for the six months ended June 30, 2016, assuming that our indebtedness remained constant throughout the period. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have any interest rate hedges in place.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Securities Exchange Act of 1934 (the "Exchange Act"), we have evaluated, under the supervision and with the participation of management of our general partner, including our general partner's principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report on Form 10-Q. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our general partner's principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our general partner's principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of June 30, 2016.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2016 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

In addition to the other information set forth in this report, readers should carefully consider the risks under the heading “Risk Factors” in our 2015 Annual Report on Form 10-K. There has been no material change in our risk factors from those described in our 2015 Annual Report on Form 10-K. These risks are not the only risks that we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition or results of operations.

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

The following table sets forth our purchases of our common units during the three months ended June 30, 2016.

Purchases of Common Units

Period	Total Number of Common Units Purchased	Average Price Paid Per Unit	Total Number of Common Units Purchased as Part of Publicly Announced Plans or Programs[2]	Maximum Dollar Value of Common Units That May Yet Be Purchased Under the Plans or Programs
April 1 – April 30, 2016	279,213	$ 14.71	279,213	$ 44,827,352
May 1 – May 31, 2016	926,273	$ 15.62	926,273	$ 30,357,077
June 1 – June 30, 2016	121,302[1]	$ 15.76	34,400	$ 29,823,895

[1] Includes units withheld to satisfy tax withholding obligations upon the vesting of certain restricted common units held by our executive officers and certain other employees.

[2] On March 4, 2016, the board of directors of our general partner authorized the repurchase of up to $50.0 million in common units over the next six months. The repurchase program authorizes us to make repurchases on a discretionary basis as determined by management, subject to market conditions, applicable legal requirements, available liquidity, and other appropriate factors. All or a portion of any repurchases may be made under a Rule 10b5-1 plan, which would permit common units to be repurchased when we might otherwise be precluded from doing so under insider trading laws. The repurchase program does not obligate us to acquire any particular amount of common units and may be modified or suspended at any time and could be terminated prior to completion.

Item 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: August 9, 2016	By: /s/ Thomas L. Carter, Jr. Thomas L. Carter, Jr. President and Chief Executive Officer (Principal Executive Officer)
Date: August 9, 2016	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., as amended (incorporated herein by reference to Exhibit 3.2 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)).
3.4	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Black Stone Minerals, L.P., dated as of April 15, 2016 (incorporated herein by reference to Exhibit 3.1 of Black Stone Minerals, L.P.'s Current Report on Form 8-K filed on April 19, 2016 (SEC File No. 001-37362)).
*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: August 9, 2016

/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: August 9, 2016

/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 “Partnership”), as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Thomas L. Carter, Jr., Chief Executive Officer of the Partnership, and Marc Carroll, Chief Financial Officer of the Partnership, each certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

Date: August 9, 2016

/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: August 9, 2016

/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.