SUBMITTED CONFIDENTIALLY TO THE DIVISION OF CORPORATION FINANCE ON OCTOBER 8, 2014

As filed with the Securities and Exchange Commission on , 2014

Registration No. 333-

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

FORM S-1
REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

Black Stone Minerals, L.P.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1311**	**47-1846692**
(State or Other Jurisdiction of Incorporation or Organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification Number)**

1001 Fannin Street
Suite 2020
Houston, Texas 77002
(713) 658-0647
(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant's Principal Executive Offices)

Steve Putman
Senior Vice President, General Counsel, and Secretary
1001 Fannin Street
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Copies to:

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Approximate date of commencement of proposed sale to the public:
As soon as practicable after this registration statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ☐

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

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.

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

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

[Table of Contents](#)

The information in this preliminary prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission becomes effective. This preliminary prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.

Subject to Completion, dated , 2014

PROSPECTUS

Black Stone Minerals, L.P.

Common Units
Representing Limited Partner Interests

This is the initial public offering of our common units representing limited partner interests in us. We are offering common units. Prior to this offering, there has been no public market for our common units. We currently expect the initial public offering price to be between $ and $ per common unit. We intend to apply to list our common units on the New York Stock Exchange under the symbol "BSM."

Investing in our common units involves risks. Please read "Risk Factors" beginning on page 25.

These risks include the following:

- We may not have sufficient available cash to pay any quarterly distribution on our common units.
- The amount of our quarterly cash distributions, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time and could make no distribution with respect to any particular quarter.
- The volatility of oil and natural gas prices due to factors beyond our control greatly affects our financial condition, results of operations, and cash available for distribution.
- We depend on various unaffiliated operators for all of the exploration, development, and production on the properties underlying our mineral and royalty interests and non-operated working interests. Substantially all of our revenue is derived from the sale of oil and gas production from producing wells in which we own a royalty interest or a non-operated working interest. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of our operators to adequately and efficiently develop and operate our acreage could have an adverse effect on our results of operations.
- Common unitholders will incur immediate and substantial dilution in net tangible book value per common unit.
- Common unitholders who are not "Eligible Holders" will not be entitled to receive distributions on or allocations of income or loss on their common units, and their common units will be subject to redemption.
- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, then our cash available for distribution to unitholders could be substantially reduced.
- Even if a unitholder does not receive any cash distributions from us, a unitholder will be required to pay taxes on its share of our taxable income.

In addition, we qualify as an "emerging growth company" as defined in the Securities Act of 1933 and, as such, are allowed to provide in this prospectus more limited disclosures than an issuer that would not so qualify. Furthermore, for so long as we remain an emerging growth company, we will qualify for certain limited exceptions from investor protection laws such as the Sarbanes-Oxley Act of 2002 and the Investor Protection and Securities Reform Act of 2010. Please read "Summary—Emerging Growth Company Status."

	Per Common Unit	Total
Public Offering Price	$	$
Underwriting Discount	$	$
Proceeds to Black Stone Minerals, L.P. (before expenses)	$	$

The underwriters may purchase up to an additional common units from us at the public offering price, less the underwriting discount, within 30 days from the date of this prospectus to cover over-allotments.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Barclays expects to deliver the common units to purchasers on or about , 2014 through the book-entry facilities of The Depository Trust Company.

Barclays

Prospectus dated , 2014

[ARTWORK]

TABLE OF CONTENTS

[Table of Contents](#)

Table of Contents

You should rely only on the information contained in this prospectus, any free-writing prospectus prepared by or on behalf of us or any other information to which we have referred you in connection with this offering. We have not, and the underwriters have not, authorized any other person to provide you with information different from that contained in this prospectus. Neither the delivery of this prospectus nor sale of our common units means that information contained in this prospectus is correct after the date of this prospectus. This prospectus is not an offer to sell or solicitation of an offer to buy our common units in any circumstances under which the offer or solicitation is unlawful.

INDUSTRY AND MARKET DATA

This prospectus includes industry data and forecasts that we obtained from internal company surveys, publicly available information, industry publications, and surveys. Our internal research and forecasts are based on management's understanding of industry conditions, and this information has not been verified by independent sources. Industry publications and surveys generally state that the information contained therein has been obtained from sources believed to be reliable, but there can be no assurance as to the accuracy or completeness of the included information. While we are not aware of any misstatements regarding industry or similar data presented herein, such data involves risks and uncertainties and is subject to change based on various factors, including those discussed under the headings "Risk Factors" and "Forward-Looking Statements" in this prospectus.

SUMMARY

This summary highlights information contained elsewhere in this prospectus. This summary does not contain all of the information that you should consider before investing in our common units. You should read the entire prospectus carefully, including the historical and pro forma financial statements and the notes to those financial statements, before investing in our common units. The information presented in this prospectus assumes an initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover page of this prospectus) and, unless otherwise indicated, that the underwriters' option to purchase additional common units is not exercised and the preferred units have not converted to common units. You should read "Risk Factors" for information about important risks that you should consider before buying our common units.

References in this prospectus to "BSMC," "Black Stone Minerals, L.P. Predecessor," "our predecessor," "we," "our," "us," or like terms when used in a historical context refer to Black Stone Minerals Company, L.P. and its subsidiaries. When used in the present tense or prospectively, "BSM," "Black Stone Minerals," "we," "our," "us," "the partnership," or like terms refer to Black Stone Minerals, L.P. and its subsidiaries, after giving effect to those transactions described in "—Formation Transactions and Structure." References in this prospectus to "BSNR" and "our general partner" refer to Black Stone Natural Resources, L.L.C., a wholly owned subsidiary and also the general partner of BSM and BSMC. References in this prospectus to "Black Stone Management" refer to Black Stone Natural Resources Management Company. References in this prospectus to "our working interests" refer to non-operated working interests. We include a glossary of some of the terms used in this prospectus as Appendix B.

Black Stone Minerals, L.P.

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 the marketing of our mineral assets for lease, creative structuring of those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working-interest basis. Our primary business objective is to grow our reserves, production, and cash flow while distributing a substantial majority of our cash flow to our common unitholders.

We own mineral interests in approximately 14.5 million acres, with an average 48.2% ownership interest in that acreage. We also own nonparticipating royalty interests in 1.2 million acres and overriding royalty interests in 1.4 million acres. These non-cost-bearing interests, which we refer to collectively as our "mineral and royalty interests," include ownership in approximately 40,000 producing wells. Our mineral and royalty interests are located in 41 states and in 62 onshore basins in the continental United States. Many of these interests are in active resource plays, including the Bakken/Three Forks play, Eagle Ford Shale, Wolfcamp play, Haynesville/Bossier play, Granite Wash play, and Fayetteville Shale, as well as emerging plays such as the Tuscaloosa Marine Shale and the Canyon Lime play. The combination of the breadth of our asset base and the long-lived, non-cost-bearing nature of our mineral and royalty interests exposes us to potential additional production and reserves from new and existing plays without investing additional capital.

Our history dates back to 1876, when W.T. Carter & Bro., a predecessor of BSMC, was established as a lumber company in Southeast Texas. W.T. Carter & Bro. acquired significant land holdings for timber, and those acquisitions typically included mineral interests. Beginning in the late 1960s, we began to divest the timber and surface rights on our properties but retained the mineral interests. We began developing our prospective oil and natural gas acreage in the 1980s. In 1985, we were involved in the discovery of the Double A Wells Field in East Texas, a natural gas field that has produced over 540 Bcfe to date. In 1992, we made our first third-party acquisition of mineral interests and, in 1998, shifted our focus from exploration to acquisitions of mineral and royalty interests. In the aggregate, we have invested approximately $1.6 billion in 42 third-party transactions involving mineral and royalty interests and, to a lesser extent, non-operated working interests. We believe that one of our key strengths is our management's extensive experience in acquiring and managing mineral and royalty interests. Our management team has a long history of creating unitholder value and has developed a scalable business model that has allowed us to integrate significant acquisitions into our existing organizational structure quickly and cost-efficiently. Our average daily production for the six months ended June 30, 2014 was approximately 25.9 MBoe/d, which includes production from our mineral and royalty interests, as well as production attributable to our working-interest participation program, as described below.

Our Assets

Mineral and Royalty Interests

Mineral interests are real-property interests that are typically perpetual and grant ownership of the oil and natural gas under a tract of land and the rights to explore for, drill for, and produce oil and natural gas on that land or to lease those exploration and development rights to a third party. When those rights are leased, usually for a three-year term, we typically receive an upfront cash payment, known as lease bonus, and we retain a mineral royalty, which entitles us to a cost-free percentage (usually ranging from 20% to 25%) of production or production revenue. A lessee can extend the lease beyond the initial lease term with continuous drilling, production, or other operating activities. When production or drilling ceases, the lease terminates, allowing us to lease the exploration and development rights to another party. Mineral interests generate the substantial majority of our revenue and are also the assets that we have the most influence over.

In addition to mineral interests, we also own other types of non-cost-bearing royalty interests, which include:

- *nonparticipating royalty interests*, or NPRIs, which are royalty interests that are carved out of the mineral estate and represent the right, which is typically perpetual, to receive a fixed, cost-free percentage of production or revenue from production, without an associated right to lease or receive lease bonus; and
- *overriding royalty interests*, or ORRIs, which are royalty interests that burden working interests and represent the right to receive a fixed, cost-free percentage of production or revenue from production from a lease. ORRIs remain in effect until the associated leases expire.

Our revenue generated from these mineral and royalty interests was $314.2 million and $173.0 million for the year ended December 31, 2013 and the six months ended June 30, 2014, respectively.

Working-Interest Participation Program

We own working interests related to our mineral interests in various plays across our asset base. Many of these working interests were acquired through working-interest participation rights, which we often include in the terms of our leases. This participation right complements our core mineral-and-royalty-interest business because it allows us to realize additional value from our minerals. Under the terms of the relevant leases, we are granted a unit-by-unit or a well-by-well option to participate on a working-interest basis in drilling opportunities on our mineral acreage. This right to participate in a unit or well is exercisable at our sole discretion. We generally only exercise this option when the results from prior drilling and production activities have substantially reduced the economic risk associated with development drilling, and where we believe the probability of achieving attractive economic returns is high.

We also own other working interests, unrelated to our mineral and royalty assets, which were acquired because of the attractive working-interest investment opportunities within the assets. The majority of these assets are focused in the Anadarko Basin, and to a lesser extent, in the Permian Basin and Powder River Basin. While these assets have been a successful part of our overall working-interest participation program, they represent approximately 10% of our 2014 non-operated working-interest capital expenditure budget and likely will be less in the future.

We collectively refer to these working interests as our “working-interest participation program.” When we participate in non-operated working interest opportunities, we are required to pay our portion of the costs associated with drilling and operating these wells. Our 2014 drilling capital expenditure budget associated with our working-interest participation program is $85.4 million, which is being invested primarily in the Bakken/Three Forks, Haynesville/Bossier, and Granite Wash plays. We historically have participated in approximately 200 new wells per year. As of June 30, 2014, we owned non-operated working interests in approximately 7,800 gross wells. For the year ended December 31, 2013 and the six months ended June 30, 2014, our revenue generated from these working interests was $123.4 million and $62.2 million, respectively.

Our Properties

Material Basins and Producing Regions

The following summarizes our exposure to the U.S. basins and regions we consider most material to our current and future business.

	Acreage(1)					Average Daily Production for Six Months Ended June 30, 2014(3) (Boe/d)
	Mineral and Royalty Interests			Working Interests		
USGS Petroleum Province(2)	Mineral Interests	NPRIs	ORRIs	Gross	Net	
Louisiana-Mississippi Salt Basins	5,270,887	111,707	65,610	55,652	7,287	6,834
Western Gulf (onshore)	1,543,217	180,901	88,138	117,148	17,659	4,910
Williston Basin	1,113,210	60,734	30,965	54,693	7,821	3,207
Palo Duro Basin	1,010,374	22,791	1,120	—	—	15
Permian Basin	678,105	541,434	61,677	8,791	4,980	843
Anadarko Basin	534,967	10,628	182,096	62,799	21,686	2,549
Appalachian Basin	490,006	416	3,532	—	—	902
East Texas Basin	406,814	36,113	27,982	127,885	32,426	2,172
Arkoma Basin	331,168	5,170	36,121	8,158	1,661	2,100
Bend Arch-Fort Worth Basin	138,018	52,208	41,072	56,001	13,408	553
Southwestern Wyoming	25,490	560	70,607	15,458	2,492	596
Other	2,927,480	188,671	789,702	59,980	13,829	1,255
Total	14,469,736	1,211,333	1,398,621	566,566	123,251	25,937

Note: Numbers may not add up to total amounts due to rounding.

(1) We may own more than one type of interest in the same tract of land. For example, where we have acquired working interests through our working-interest participation program in a given tract, our working-interest acreage in that tract will relate to the same tract acres as our mineral-interest acreage in that tract. Consequently, some of the acreage shown for one type of interest above may also be included in the acreage shown for another type of interest. Because of our working-interest participation program, overlap between working-interest acreage and mineral-and-royalty-interest acreage is significant, while overlap between the different types of mineral and royalty interests is not. Working-interest acreage excludes acreage that is not quantifiable due to incomplete seller records.

(2) The basins and regions shown in the table are consistent with U.S. Geological Survey (“USGS”) delineations of petroleum provinces of onshore and state offshore areas in the continental United States. We refer to these petroleum provinces as “basins” or “regions.”

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

- ***Louisiana-Mississippi Salt Basins.*** The Louisiana-Mississippi Salt Basins region ranges from northern Louisiana and southern Arkansas through south central and southern Mississippi, southern Alabama, and the Florida Panhandle. The Haynesville/Bossier play, which has been extensively delineated through drilling, is the most prospective unconventional play for natural gas production and reserves within this region. Approximately half of the Haynesville/Bossier play's prospective acreage is within the Louisiana-Mississippi Salt Basins region, where we own significant mineral and royalty interests and working interests. The Tuscaloosa Marine Shale play is the basin's most significant emerging unconventional oil play, extending through southwestern Mississippi and southeastern Louisiana on the eastern end of the play and westward across central Louisiana to the Texas border. The play is in the early stage of development and is actively being drilled and tested by several operators. We have a significant mineral-and-royalty-interest position across the entire basin, with material exposure to the Tuscaloosa Marine Shale. There are a number of additional active conventional and unconventional plays in the basin in which we hold considerable mineral and royalty interests, including the Brown Dense, Cotton Valley, Hosston, Norphlet, Smackover, and Wilcox plays.
- ***Western Gulf.*** The Western Gulf region, which ranges from South Texas through southeastern Louisiana, includes a variety of both conventional and unconventional plays. We have extensive exposure to the Eagle Ford Shale in South Texas, where we are experiencing a significant level of development drilling on our mineral interests within the oil and rich-gas condensate areas of the play. We also have significant exposure to the Tuscaloosa Marine Shale in central and southeastern Louisiana, which is one of the most prospective emerging oil shale plays in the basin and is being actively drilled and tested by several operators in the Western Gulf region. In addition to the Eagle Ford Shale and Tuscaloosa Marine Shale plays, there are a number of other active conventional and unconventional plays to which we have exposure to in the region, including the Austin Chalk, Buda, Eaglebine (or Maness) Shale, Frio, Glenrose, Olmos, Woodbine, Vicksburg, Wilcox, and Yegua plays.
- ***Williston Basin.*** The Williston Basin stretches through all of North Dakota, the northwest part of South Dakota, and eastern Montana and includes plays such as the Bakken/Three Forks play, where we have significant exposure through our mineral and royalty interests as well as through our working interests. We are also exposed to other well-known plays in the basin, including the Duperow, Mission Canyon, Madison, Ratcliff, Red River, and Spearfish plays.
- ***Palo Duro Basin.*** The Palo Duro Basin covers much of the Texas Panhandle but also occupies a small portion of the Oklahoma Panhandle and extends partially into New Mexico to the west. We have a significant acreage position in the Palo Duro Basin, much of which underlies an emerging unconventional oil play in the Canyon Lime. We are also well positioned relative to a number of other active conventional and unconventional plays in the Palo Duro Basin, including the Brown Dolomite, Canyon Wash, Cisco Sand, and Strawn Wash plays.
- ***Permian Basin.*** The Permian Basin ranges from southeastern New Mexico into West Texas and is currently one of the most active areas for drilling in the United States. It includes three geologic provinces: the Midland Basin to the east, the Delaware Basin to the west, and the Central Basin in between. Our acreage underlies prospective areas for the Wolfcamp play in the Midland and Delaware Basins, the Spraberry formation in the Midland Basin, and the Bone Springs formation in the Delaware Basin, which are among the plays most actively targeted by drillers within the basin. In addition to these plays, we own mineral and royalty interests that are prospective for a number of other active conventional and unconventional plays in the Permian Basin, including the Atoka, Clearfork, Ellenberger, San Andres, Strawn, and Wichita Albany plays.

- ***Anadarko Basin*****.** The Anadarko Basin encompasses the Texas Panhandle, southeastern Colorado, southwestern Kansas, and western Oklahoma. We own mineral and royalty interests as well as working interests in prospective areas for most of the prolific plays in this basin, including the Granite Wash, Atoka, Cleveland, and Woodford Shale plays. Other active plays in which we hold interests in prospective acreage include the Cottage Grove, Hogshooter, Marmaton, Springer, and Tonkawa plays.
- ***Appalachian Basin*****.** The Appalachian Basin covers most of Pennsylvania, eastern Ohio, West Virginia, western Maryland, eastern Kentucky, central Tennessee, western Virginia, northwestern Georgia, and northern Alabama. The basin's most active play in which we have acreage is the Marcellus Shale, which covers most of western Pennsylvania and the northern part of West Virginia. In addition to the Marcellus Shale, there are a number of other active conventional and unconventional plays to which we have material exposure in the Appalachian Basin, including the Berea, Big Injun, Devonian, Huron, Rhinestreet, and Utica plays.
- ***East Texas Basin*****.** The East Texas Basin ranges from central East Texas to northeast Texas and includes the Haynesville/Bossier play and the Cotton Valley play, which are among the most prolific gas plays in the basin. We own a material acreage position in the Shelby Trough area of the Haynesville/Bossier play located in San Augustine and Nacogdoches Counties, which is one of the most active areas being drilled today for that play in the East Texas Basin. There are other active plays to which we have significant exposure, including the Bossier Sand, Goodland Lime, James Lime, Pettit, Travis Peak, Smackover, and Woodbine plays.
- ***Arkoma Basin*****.** The Arkoma Basin stretches from southeast Oklahoma through central Arkansas. The Fayetteville Shale play is one of the basin's most active unconventional gas plays. We own material mineral and royalty interests within the prospective area of the Fayetteville Shale. In addition, we have interests exposed to a number of other active conventional and unconventional plays in the basin, including the Atoka, Cromwell, Dunn, Hale, and Woodford Shale plays.
- ***Bend Arch-Fort Worth Basin*****.** The Bend Arch-Fort Worth Basin covers much of north central Texas and includes the Barnett Shale play as its most active unconventional play. Through our mineral and royalty interest in this basin, we have significant exposure to the Barnett Shale as well as a number of other active conventional and unconventional plays in the basin, including the Bend Conglomerate, Caddo, Marble Falls, and Mississippian Lime plays.
- ***Southwestern Wyoming*****.** The Southwestern Wyoming region covers most of southern and western Wyoming. The Pinedale Anticline is one of the basin's largest producing fields and mainly produces from the Lance formation. We have a meaningful position in the Pinedale Anticline, and we have interests prospective for other active plays as well, including the Mesaverde, Niobrara, and Wasatch plays.

For more detailed information about the basins and regions described above, please read "Business—Our Properties—Material Basins and Producing Regions."

Material Resource Plays

The following table presents information about our mineral-and-royalty-interest and working-interest acreage by the resource plays we consider most material to our current and future business and contribute approximately 60% of our aggregate production for the six months ended June 30, 2014.

	Acreage(1)				
	Mineral and Royalty Interests			Working Interests	
Resource Play(2)	Mineral Interests	NPRIs	ORRIs	Gross	Net
Bakken Shale	318,990	35,261	12,930	49,799	7,075
Three Forks	296,689	32,442	12,250	50,000	6,752
Haynesville Shale	274,996	7,078	53,191	168,451	38,256
Marcellus Shale	253,536	—	1,002	—	—
Canyon Lime	232,381	—	—	—	—
Bossier Shale	213,276	2,096	47,124	144,619	35,002
Tuscaloosa Marine Shale	181,560	4,081	22,674	—	—
Granite Wash	110,654	4,122	87,920	5,194	1,364
Fayetteville Shale	76,539	—	12,160	—	—
Barnett Shale	62,171	4,644	35,872	48,282	12,440
Eagle Ford Shale	47,683	85,063	33,532	235	118
Wolfcamp-Delaware	44,855	18,825	1,080	520	89
Wolfcamp-Midland	36,909	38,513	14,804	160	4

(1) We may own more than one type of interest in the same tract of land. For example, where we have acquired working interests through our working-interest participation program in a given tract, our working-interest acreage in that tract will relate to the same tract acres as our mineral-interest acreage in that tract. Consequently, some of the acreage shown for one type of interest above may also be included in the acreage shown for another type of interest. Because of our working-interest participation program, overlap between working-interest acreage and mineral-and-royalty-interest acreage is significant, while overlap between the different types of mineral and royalty interests is not. Working-interest acreage excludes acreage that is not quantifiable due to incomplete seller records.

(2) The plays above have been delineated based on information from the U.S. Energy Information Administration (“EIA”), the USGS, state agencies, or according to areas of the most active industry development.

Business Strategies

Our primary business objective is to grow our reserves, production, and cash flow over the long term, while distributing a substantial majority of our cash flow to our common unitholders. We intend to accomplish this objective by continuing to execute the following strategies:

- ***Actively lease our minerals to third-party operators.*** We intend to continue actively marketing our mineral interests for lease in order to generate income from lease bonus and ensure that our acreage is drilled as quickly as possible. Our staff actively manages the leasing of our acreage in order to accelerate royalty revenue and maximize our working-interest optionality. While our leasing activity generates significant revenue from lease bonus, the size and frequency of lease bonus vary depending on the oil and natural gas industry’s perception of the prospectivity, risk, and potential economics of a play. During the lease-negotiation process, we consider standard industry lease terms as well as innovative terms that are designed to encourage more exploration. Through our control of large blocks of contiguous acreage throughout the country, we provide exploration and production companies with an extensive acreage inventory from which to generate prospects and search for new opportunities. In addition, our in-house geological and geophysical team uses our extensive seismic library to assist exploration and production companies in the identification of emerging plays and potential drilling locations.

- ***Acquire additional mineral and royalty interests in oil and natural gas properties that meet our acquisition criteria.*** We intend to continue to acquire mineral and royalty interests that have substantial resource and cost-free, or organic, growth potential. Our management team has a long history of evaluating, pursuing, and consummating acquisitions of oil and natural gas mineral and royalty interests in the United States. We believe that our large network of industry relationships provides us with a competitive advantage in pursuing potential acquisition opportunities. Since 1992, we have invested approximately $1.6 billion in 42 acquisitions. In the future, we expect to focus on relatively large acquisitions but will also continue to pursue smaller mineral packages to complement an existing position or to establish a foothold in an emerging play. We prefer acquisitions that meet the following criteria:
  - sufficient current production to create near-term accretion for our unitholders;
  - geologic support for future production and reserve growth;
  - a geographic footprint that we believe is complementary to our diverse portfolio and maximizes our potential for upside reserve and production growth from undiscovered reserves or new plays; and
  - targeted positions in high-growth resource and conventional plays.
- ***Participate in drilling opportunities in low-risk plays that generate attractive returns.*** Our ownership of mineral interests affords us the favorable position of negotiating leases that frequently provide us a unit-by-unit or well-by-well option to participate on a working-interest basis in economic, low-risk drilling opportunities. This participation program offers access to drilling opportunities in established producing trends at well-level economics, often unburdened by traditional land and exploration costs associated with acquiring prospective acreage, such as paying lease bonus, acquiring seismic data, and drilling exploratory and delineation wells. We expect to continue to actively participate in these drilling opportunities.
- ***Maintain a conservative capital structure and prudently manage the business for the long term.*** We are committed to maintaining a conservative capital structure that will afford us the financial flexibility to execute our business strategies on an ongoing basis. Upon completion of this offering, we will have no outstanding indebtedness. We believe that proceeds from this offering, internally generated cash flows, our $ million borrowing base under our credit facility, and access to the public capital markets will provide us with sufficient liquidity and financial flexibility to grow our production, reserves, and cash flow through the continued development of our existing assets and accretive acquisitions of mineral and royalty interests.

Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies and achieve our primary business objective:

- ***Significant diversified portfolio of mineral and royalty interests in mature producing basins and exposure to prospective exploration opportunities.*** We have a large-scale, diversified asset base with exposure to active high-quality conventional and unconventional plays. With our mineral and royalty interests spanning over 16.5 million total acres across the continental United States, we have established a strong position with significant growth opportunities and exposure to potentially large new discoveries in the future. In some cases, we have built our positions in anticipation of development in a play, as we did in the Eagle Ford Shale. In other cases, we acquired diversified mineral packages in rich geologic basins with multiple prospective horizons from which subsequent resource plays, including the Bakken/Three Forks play and the Haynesville/Bossier play, have developed. Because our asset base is large and diversified, we are able to make significant focused acquisitions in active areas within well-established resource plays, while maintaining overall diversity. Furthermore, the geographic breadth of our assets and vast quantity of our property interests expose us to potential production and reserves from new and existing plays without further required investment on our behalf. We believe that we will continue to benefit from these cost-free additions of production and reserves for the foreseeable future as a result of technological advances and continuing interest by third-party producers in exploration and development activities on our acreage.

- ***Exposure to many of the leading resource plays in the United States***. We expect our reserves and cash available for distributions per unit to grow organically for the next several years as our operators continue to drill new wells on the acreage we have leased to them. We believe that we have significant drilling inventory remaining in our interests in multiple resource plays.
- ***Ability to increase exposure in most economic plays through our working-interest participation program***. We frequently negotiate our leases with options to participate in wells on a working-interest basis. This working-interest option allows us to increase our exposure to plays that we find attractive when the results from prior drilling and production have substantially reduced the economic risk associated with development drilling and where we believe the probability of achieving attractive economic returns is high. We intend to continue increasing our exposure to those opportunities.
- ***Scalable business model***. We believe that our size, organizational structure, and capacity give us a relative advantage in growing our business because we are able to add large packages of mineral and royalty interests without significantly increasing our cost structure, allowing us to be more competitive when pursuing acquisition opportunities. Our land, accounting, engineering and geology, information-technology, and business-development departments have developed a scalable business model that allows us to manage our existing assets efficiently and absorb significant acquisitions without material cost increases.
- ***Exposure to natural gas supply and demand growth***. The EIA projects that U.S. natural gas demand from internal consumption is expected to increase from 25.6 trillion cubic feet in 2012 to 31.6 trillion cubic feet in 2040, driven primarily by increased electricity generation and industrial use. International demand for exports of U.S. natural gas, through pipelines and liquefied natural gas, is forecasted to grow to 5.8 trillion cubic feet per year by 2040. The EIA forecasts the total demand for U.S. natural gas to reach 37.4 trillion cubic feet in 2040. As a result of this increase in demand, the EIA projects U.S. natural gas production to increase from 24.1 trillion cubic feet in 2012 to 37.5 trillion cubic feet in 2040, a 56% increase. Almost all of this increase is due to projected growth in natural gas production from resource plays, which is projected to grow from 9.7 trillion cubic feet in 2012 to 19.8 trillion cubic feet in 2040. We have significant exposure to domestic natural gas resource plays, including the Haynesville/Bossier play, the Fayetteville Shale, and the Barnett Shale, and we believe that these assets will provide meaningful upside in production and revenue growth as demand for natural gas increases. Our gas assets throughout the U.S. Gulf Coast are well-positioned geographically to take advantage of the growing liquefied natural gas export market.
- ***Financial flexibility to fund expansion***. Upon the completion of this offering and the application of the net proceeds as set forth under "Use of Proceeds," we expect to have no indebtedness outstanding, approximately $ million of cash on hand, and $ million of undrawn borrowing capacity under our credit facility. The credit facility, combined with internally generated cash flow and access to the public capital markets, will provide us with the financial capacity and flexibility to grow our business.
- ***Experienced and proven management team***. The members of our executive team have an average of over 25 years of industry experience and have a proven track record of executing accretive acquisitions and maximizing asset development. We expect to benefit from the longstanding relationships fostered by our management team within the industry and the decades-long track record of successful acquisitions of mineral and royalty interests. We believe the experience of our management team in acquiring and managing mineral and royalty interests will allow us to continue to grow our production, reserves, and distributions.

Management

We are managed and operated by the board of directors and executive officers of our general partner, Black Stone Natural Resources, L.L.C., a wholly owned subsidiary of BSMC. In connection with the closing of this offering, we will complete a series of transactions pursuant to which, among other things, BSMC and BSNR will become our wholly owned subsidiaries. Please read "—Formation Transactions and Structure." Our partnership agreement provides that our limited partners holding common and preferred units have the right to nominate and vote in the election of directors to the board of directors of our general partner. The board of directors of our general partner must have at least three directors who meet the independence standards established by the New York Stock Exchange (the "NYSE") within one year of the consummation of this offering. At least one independent director will be appointed by the time our common units are first listed for trading on the NYSE.

Our partnership agreement provides that an annual meeting of the limited partners for the election of directors to the board of directors of our general partner will be held at a date and time as may be fixed from time to time by our general partner. At each annual meeting, the limited partners authorized to vote will elect by a plurality of the votes cast at the meeting persons to serve as directors on the board of directors of our general partner who are nominated in accordance with the provisions of our partnership agreement. At all elections of the board of directors of our general partner, each limited partner authorized to vote will be entitled to cumulate his or her votes and give one candidate, or divide among any number of candidates, a number of votes equal to the product of (x) the number of units held by each limited partner, multiplied by (y) the number of directors to be elected at the meeting.

Fiduciary Duties

Our partnership agreement contains provisions that eliminate the fiduciary duties to which our general partner and the directors and executive officers of our general partner would otherwise be held by state fiduciary duty law and imposes contractual standards that our general partner and its directors and executive officers must follow. Our partnership agreement also specifically restricts the situations in which remedies may be available to our unitholders for actions taken that might otherwise constitute breaches of duty under applicable Delaware law or breaches of the contractual obligations in our partnership agreement. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and each unitholder is treated as having consented to various actions contemplated in the partnership agreement that might otherwise be considered a breach of fiduciary or other duties under Delaware law.

For a more detailed description of the duties of our general partner and its directors and executive officers, please read "Fiduciary Duties."

Emerging Growth Company Status

We are an "emerging growth company" as defined in the Jumpstart Our Business Startups Act ("JOBS Act"). For as long as we are an emerging growth company, we may take advantage of specified exemptions from reporting and other regulatory requirements that are otherwise generally applicable to other public companies. These exemptions include:

- an exemption from providing an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act");
- an exemption from compliance with any new requirements adopted by the Public Company Accounting Oversight Board ("PCAOB"), requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;

- an exemption from compliance with any other new auditing standards adopted by the PCAOB after April 5, 2012, unless the SEC determines otherwise; and
- reduced disclosure of executive compensation.

In addition, Section 107 of the JOBS Act also provides that an emerging growth company can use the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. This permits an emerging growth company to delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. However, we are choosing to "opt out" of this extended transition period and, as a result, we will comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. Our decision to opt out of the extended transition period for complying with new or revised accounting standards is irrevocable.

We will cease to be an "emerging growth company" upon the earliest of (i) when we have $1.0 billion or more in annual revenues; (ii) when we issue more than $1.0 billion of non-convertible debt over a three-year period; (iii) the last day of the fiscal year following the fifth anniversary of our initial public offering; or (iv) when we have qualified as a "large accelerated filer," which refers to when we (w) will have an aggregate worldwide market value of voting and non-voting common units held by our non-affiliates of $700 million or more, as of the last business day of our most recently completed second fiscal quarter, (x) have been subject to the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), for a period of at least 12 calendar months, (y) have filed at least one annual report pursuant to Section 13(a) or 15(d) of the Exchange Act, and (z) no longer be eligible to use the requirements for "smaller reporting companies," as defined in the Exchange Act, for our annual and quarterly reports.

Formation Transactions and Structure

In connection with this offering, the following transactions have occurred or will occur:

- BSNR will contribute cash to (i) BSMC in exchange for common units representing a 1% limited partner interest in BSMC and (ii) the partnership in exchange for common units representing a 1% limited partner interest in the partnership;
- BSMC will merge with and into a wholly owned subsidiary of the partnership ("Merger Sub") with BSMC as the surviving entity;
- in connection with the merger, (i) the partnership will redeem the limited partner interest in it held by BSMC, (ii) the common units and the preferred units of BSMC (other than those common units of BSMC that are held by BSNR) will be exchanged for an aggregate of of the partnership's common units and of the partnership's preferred units, respectively, (iii) the common units of BSMC that are held by BSNR will be exchanged for a 1% limited partner interest in BSMC, (iv) the non-economic general partner interest in the partnership held by BSNR will continue to be outstanding, and (v) the partnership's 100% equity interest in Merger Sub will be converted into a 99% limited partner interest in BSMC, and the non-economic general partner interest in BSMC held by BSNR will continue to be outstanding;
- immediately following the merger, the limited partnership agreement of BSMC and the limited liability company agreement of BSNR will be amended and restated;
- the partnership will amend and restate its credit facility;
- the partnership will enter into a registration rights agreement under which certain of its affiliates will have the right to cause it to register the offer and sale of any units that they hold under the Securities Act and applicable state securities laws; and

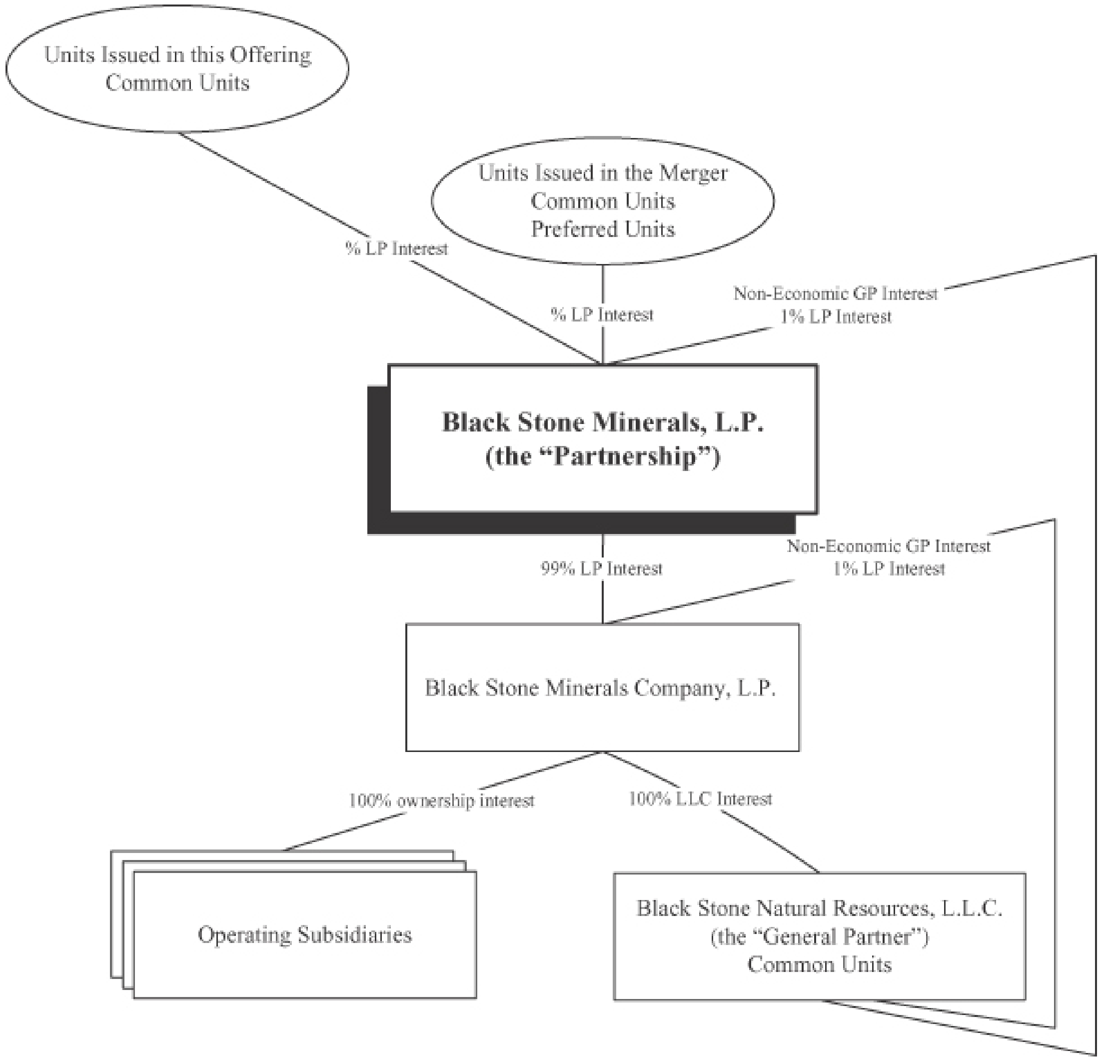
- the partnership will issue and sell common units to the public in this offering and use the net proceeds from this offering in the manner described under "Use of Proceeds."

We refer to these transactions collectively as the "formation transactions."

We have granted the underwriters a 30-day option to purchase up to an aggregate of additional common units. Any net proceeds received from the exercise of this option will be used to fund future capital expenditures.

Table of Contents

The following chart illustrates our organizational structure after giving effect to this offering and the other formation transactions described above:



Common units issued in this offering	%
Units issued in the merger:	
Common units	%
Preferred units	%
Interests held by our general partner:	
Non-economic general partner interest	0.0%
Common units	%
	100.0%

Principal Executive Offices

Our principal executive offices are located at 1001 Fannin Street, Suite 2020, Houston, Texas 77002, and our telephone number is (713) 658-0647. Our website address will be *www.   .com*. We intend to make our periodic reports and other information filed with or furnished to the SEC available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

Risk Factors

An investment in our common units involves risks. You should carefully consider the following considerations, the risks described in "Risk Factors" and the other information in this prospectus, before deciding whether to invest in our common units. If any of these risks were to occur, our financial condition, results of our operations, cash flows, and ability to make distributions to our unitholders would be adversely affected, and you could lose all or part of your investment.

Risks Related to Our Business

- We may not have sufficient available cash to pay any quarterly distribution on our common units.
- The assumptions underlying the forecast of cash available for distribution that we include in "Cash Distribution Policy and Restrictions on Distributions" may prove inaccurate and are subject to significant risks and uncertainties, which could cause actual results to differ materially from our forecasted results.
- The amount of cash we have available for distribution to holders of our units depends primarily on our cash flow and not our profitability, which may prevent us from making cash distributions during periods when we record net income.
- The amount of our quarterly cash distributions, if any, may vary significantly, both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time and could make no distribution with respect to any particular quarter.
- The volatility of oil and natural gas prices due to factors beyond our control greatly affects our financial condition, results of operations and cash available for distribution.
- Natural gas prices have declined substantially from historical highs and are expected to remain depressed for the foreseeable future. Approximately 74.2% of our 2013 production and 71.8% of our production in the first six months of 2014, on an MBoe basis, was natural gas. Any additional decreases in prices of natural gas may adversely affect our cash flow, results of operations, and financial position, perhaps materially.
- Our failure to successfully identify, complete, and integrate acquisitions could adversely affect our growth, results of operations, and cash available for distribution.
- Any acquisitions of additional mineral and royalty interests that we complete will be subject to substantial risks.
- Title to the properties in which we have an interest may be impaired by title defects.
- We depend on various unaffiliated operators for all of the exploration, development, and production on the properties underlying our mineral and royalty interests and non-operated working interests. Substantially all of our revenue is derived from the sale of oil and gas production from producing wells in which we own a royalty interest or a non-operated working interest. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of our operators to adequately and efficiently develop and operate our acreage could have an adverse effect on our results of operations.
- We may experience delays in the payment of royalties and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

- Acquisitions, funding our working-interest participation program, and our operators' development activities of our leases will require substantial capital, and we and our operators may be unable to obtain needed capital or financing on satisfactory terms or at all.
- Unless we replace the oil and natural gas produced from our properties, our cash flow from operations and our ability to make distributions to our common unitholders could be adversely affected.
- We either have little or no control over the timing of future drilling with respect to our mineral and royalty interests and non-operated working interests.
- Project areas on our properties, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.
- Our operators' identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- The unavailability, high cost, or shortages of rigs, equipment, raw materials, supplies, or personnel may restrict or result in increased costs for operators related to developing and operating our properties.
- The marketability of oil and natural gas production is dependent upon transportation, pipelines, and refining facilities, which neither we nor many of our operators control. Any limitation in the availability of those facilities could interfere with our or our operators' ability to market our or our operators' production and could harm our business.
- Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- Conservation measures and technological advances could reduce demand for oil and natural gas.
- We rely on a few key individuals whose absence or loss could adversely affect our business.
- The results of exploratory drilling in shale plays will be subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.
- Oil and natural gas operations are subject to various governmental laws and regulations. Compliance with these laws and regulations can be burdensome and expensive, and failure to comply could result in significant liabilities, which could reduce our cash available for distribution.
- Louisiana mineral servitudes are subject to reversion to the surface owner after ten years' nonuse.
- Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays, and fewer potential drilling locations.
- The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas that our operators produce.
- Operating hazards and uninsured risks may result in substantial losses to us or our operators, and any losses could adversely affect our results of operations and cash available for distribution.
- Cyber attacks could significantly affect us.

Risks Inherent in an Investment in Us

- The board of directors of our general partner will adopt a policy to distribute a substantial majority of the available cash we generate each quarter, which could limit our ability to grow and make acquisitions.
- The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all. If we

make distributions, our preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our preferred units are outstanding.

- Our partnership agreement eliminates the fiduciary duties that might otherwise be owed to the partnership and its partners by our general partner and its directors and executive officers under Delaware law.
- Our partnership agreement restricts the situations in which remedies may be available to our unitholders for actions taken that might constitute breaches of duty under applicable Delaware law and breaches of the contractual obligations in our partnership agreement.
- Our partnership agreement restricts the voting rights of unitholders owning 15% or more of our common units, subject to certain exceptions.
- We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions to you.
- Unitholders may not have limited liability if a court finds that unitholder action constitutes participation in control of our business.
- Unitholders may have liability to repay distributions and in certain circumstances may be personally liable for the obligations of the partnership.
- Increases in interest rates may cause the market price of our common units to decline.
- Common unitholders will incur immediate and substantial dilution in net tangible book value per common unit.
- We may issue additional common units and other equity interests without common unitholder approval, which would dilute holders of common units. However, our partnership agreement does not authorize us to issue units ranking senior to or at parity with our preferred units without preferred unitholder approval.
- The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets.
- There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and unitholders could lose all or part of their investment.
- We will incur increased costs as a result of being a publicly traded partnership.
- For as long as we are an emerging growth company, we will not be required to comply with certain disclosure requirements, including those relating to accounting standards, disclosure about our executive compensation and internal control auditing requirements that apply to other public companies.
- If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.
- The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.
- Our partnership agreement includes exclusive forum, venue, and jurisdiction provisions. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions, or proceedings, and submitting to the exclusive jurisdiction of Delaware courts. Our partnership agreement also provides that any limited partner holding common units bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with an unsuccessful action.

- Our general partner may amend our partnership agreement, as it determines necessary or advisable, to permit the general partner to redeem the units of certain common unitholders.
- Common unitholders who are not “Eligible Holders” will not be entitled to receive distributions on or allocations of income or loss on their common units, and their common units will be subject to redemption.

Tax Risks to Common Unitholders

- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (“IRS”) were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, then our cash available for distribution to unitholders could be substantially reduced.
- The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial, or administrative changes or differing interpretations, possibly applied on a retroactive basis.
- If the IRS were to contest the federal income tax positions we take, it may adversely affect the market for our common units, and the costs of any contest would reduce cash available for distribution to our unitholders.
- Even if a unitholder does not receive any cash distributions from us, a unitholder will be required to pay taxes on its share of our taxable income.
- Tax gain or loss on disposition of our common units could be more or less than expected.
- Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.
- We will treat each purchaser of common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.
- We will prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss, and deduction among our unitholders.
- A unitholder whose units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and could recognize gain or loss from the disposition.
- The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.
- You may be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

The Offering

Common units offered to the public	common units (common units if the underwriters exercise in full their option to purchase additional common units from us).
Units outstanding after this offering	common units (common units if the underwriters exercise in full their option to purchase additional common units from us) and preferred units.
Use of proceeds	We intend to use the estimated net proceeds of approximately $ million from this offering (based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover page of this prospectus), after deducting the estimated underwriting discount and offering expenses payable by us, to repay all of the indebtedness outstanding under our credit facility and to fund future capital expenditures. The net proceeds from any exercise of the underwriters' option to purchase additional common units (approximately $ million based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover page of this prospectus, after deducting the estimated underwriting discount, if exercised in full) will be used to fund future capital expenditures. Please read "Use of Proceeds." Affiliates of certain of our underwriters are lenders under our credit facility and, as such, may receive a portion of the proceeds from this offering. Please read "Underwriting—Relationships."
Cash distributions	Within 60 days after the end of each quarter, beginning with the quarter ending , 2015, we expect to make distributions to common unitholders of record on the applicable record date. We expect our first distribution will consist of available cash for the period from the closing of this offering through , 2015. If we make distributions, our preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our preferred units are outstanding. When all of our preferred units have been redeemed or converted to common units, all distributions will be made pro rata to our common unitholders. In connection with the closing of this offering, the board of directors of our general partner will adopt a policy pursuant to which we will distribute a substantial majority of the available cash we generate each quarter. Available cash for each quarter will be determined by the board of directors of our general partner following the end of that quarter. Our initial distribution will be $ per common unit on an annualized basis, which we forecast to represent approximately %

of our available cash for the year ending December 31, 2015. It is our intent, for at least the next several years, to finance most of our acquisition and working-interest capital needs with the retained net proceeds from this offering, borrowings under our credit facility, and, in certain circumstances, proceeds from future equity and debt issuances. We may also borrow to make distributions to our unitholders where, for example, we believe that the distribution level is sustainable over the long term, but short-term factors may cause available cash from operations to be insufficient to pay distributions at the current level. The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time. Our partnership agreement does not require us to pay cash distributions on a quarterly or other basis. Please read "Risk Factors—Risks Inherent in an Investment in Us—The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all. If we make distributions, our preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our preferred units are outstanding."

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. Unlike a number of other master limited partnerships, we do not expect to initially retain cash from our operations for replacement capital expenditures, primarily due to our expectation that the development of existing plays and the discovery of new resources on our mineral and royalty interests will add reserves and will lead to increasing revenues for at least the next several years. We also intend to add reserves through acquisitions of mineral and royalty interests and through non-operated working-interest participation. We may restrict distributions to fund acquisitions and participation in working interests in whole or in part. If we do not retain cash for capital expenditures in amounts necessary to maintain our asset base, our cash available for distribution per unit will decrease over time. The board of directors of our general partner may in the future decide to withhold capital expenditures from cash available for distribution, which may have an adverse impact on the cash available for distribution per unit in the quarter in which those amounts are withheld. To the extent that we do not withhold cash for capital expenditures in the future, a portion of our future cash available for distribution will represent a return of your capital.

Subordinated units	None.
Incentive distribution rights	None.

Issuance of additional units	Our partnership agreement authorizes us to issue an unlimited number of additional units, including units that are senior to the common units, without the approval of our unitholders. However, our partnership agreement does not authorize us to issue securities having preferences or rights with priority over or on a parity with the preferred units with respect to rights to share in distributions, redemption obligations, or redemption rights unless we receive the approval of our preferred unitholders. Please read "Units Eligible for Future Sale," "The Partnership Agreement—Issuance of Additional Partnership Interests" and "Description of Our Preferred Units."
Estimated ratio of taxable income to distributions	We estimate that if you own the common units you purchase in this offering through the record date for distributions for the period ending December 31, , you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately % of the cash expected to be distributed to you with respect to that period. Because of the nature of our business and the expected variability of our quarterly distributions, however, the ratio of our taxable income to distributions may vary significantly from one year to another. Please read "Material U.S. Federal Income Tax Consequences—Tax Consequences of Unit Ownership" for the basis of this estimate.
Material federal income tax consequences	For a discussion of the material federal income tax consequences that may be relevant to unitholders who are individual citizens or residents of the United States, please read "Material U.S. Federal Income Tax Consequences."
Exchange listing	We intend to apply to list our common units on the NYSE under the symbol "BSM."

Summary Historical and Pro Forma Financial Data

Black Stone Minerals, L.P. was formed in September 2014 and does not have historical financial statements. Therefore, in this prospectus we present the historical financial statements of BSMC, our predecessor for accounting purposes. We refer to this entity as “Black Stone Minerals, L.P. Predecessor.” The following table presents summary historical financial data of BSMC and summary pro forma financial data of Black Stone Minerals, L.P. as of the dates and for the periods indicated.

The summary historical financial data presented as of and for the years ended December 31, 2013 and 2012 are derived from the audited historical financial statements of BSMC that are included elsewhere in this prospectus. The summary historical financial data presented as of and for the six months ended June 30, 2014 and for the six months ended June 30, 2013 are derived from the unaudited historical financial statements of BSMC included elsewhere in this prospectus.

The summary pro forma financial data presented for the year ended December 31, 2013 and as of and for the six months ended June 30, 2014 are derived from our pro forma financial statements included elsewhere in this prospectus. Our pro forma financial statements give pro forma effect to the issuance and sale of the common units in this offering and the application of the net proceeds therefrom as described under “Use of Proceeds.” The pro forma balance sheet assumes the events described above occurred as of June 30, 2014. The pro forma statements of operations for the year ended December 31, 2013 and the six months ended June 30, 2014 assume the events described above occurred as of January 1, 2013.

We have not given pro forma effect to incremental general and administrative expenses of approximately $ million that we expect to incur annually as a result of operating as a publicly traded partnership, such as expenses associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NYSE listing, independent-auditor fees, legal fees, investor-relations activities, registrar and transfer agent fees, director-and-officer insurance, and additional compensation.

Table of Contents

For a detailed discussion of the summary historical financial data contained in the following table, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The following table should also be read in conjunction with “Use of Proceeds” and the audited and unaudited historical financial statements of BSMC and our pro forma financial statements included elsewhere in this prospectus. Among other things, the historical financial statements include more detailed information regarding the basis of presentation for the information in the following table.

	Black Stone Minerals, L.P. Predecessor Historical				Black Stone Minerals, L.P. Pro Forma	
	Year Ended December 31,		Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	2012	2013	2013	2014	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Revenues:						
Oil and condensate sales	$ 202,104	$ 252,742	$ 118,615	$ 124,576	$ 252,742	$ 124,576
Natural gas and natural gas liquids sales	166,849	184,868	95,335	110,640	184,868	110,640
Gain (loss) on commodity derivative instruments	12,275	(5,860)	1,522	(8,343)	(5,860)	(8,343)
Lease bonus and other income	53,918	31,809	7,155	19,476	31,809	19,476
Total revenues	$ 435,146	$ 463,559	$ 222,627	$ 246,349	$ 463,559	$ 246,349
Operating Expenses:						
Lease operating expense and other	$ 20,527	$ 21,316	$ 10,347	$ 9,674	$ 21,316	$ 9,674
Production and ad valorem taxes	36,680	42,813	19,340	21,408	42,813	21,408
Depreciation, depletion and amortization	104,059	102,442	51,090	46,993	102,442	46,993
Impairment of oil and natural gas properties	62,987	57,109	27,630	—	57,109	—
General and administrative expense	50,348	59,501	28,940	29,963	59,501	29,963
Accretion of asset retirement obligations	608	588	307	295	588	295
Total operating expenses	$ 275,209	$ 283,769	$ 137,654	$ 108,333	$ 283,769	$ 108,333
Income from operations	$ 159,937	$ 179,790	$ 84,973	$ 138,016	$ 179,790	$ 138,016
Other income (expense):						
Interest and investment income	$ 209	$ 90	$ 65	$ 24	$ 90	$ 24
Interest expense(1)	(9,166)	(11,342)	(4,747)	(6,852)	(3,633)	(1,835)
Gain on sale of assets	363	18	18	—	18	—
Other income	467	407	137	807	407	807
Total other income (expense)	(8,127)	(10,827)	(4,527)	(6,021)	(3,118)	(1,004)
Net income	$ 151,810	$ 168,963	$ 80,446	$ 131,995	$ 176,672	$ 137,012
Statement of Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 358,002	$ 320,764	$ 142,900	$ 165,860		
Investing activities	(198,975)	(195,631)	(123,855)	(59,855)		
Financing activities	(138,172)	(142,311)	(44,441)	(123,339)		
Other Financial Data:						
EBITDA(2)	$ 328,630	$ 340,444	$ 164,220	$ 186,135	$ 340,444	$ 186,135
Adjusted EBITDA(2)	346,574	354,576	167,942	197,189	354,576	197,189
Capital expenditures(3)	(198,975)	(195,631)	(123,855)	(59,855)		
Balance Sheet Data (at period end):						
Cash and cash equivalents	$ 47,301	$ 30,123		$ 12,789		$
Total assets	1,199,187	1,444,413		1,466,769		
Long-term debt (including current portion)	363,100	451,000		453,000		—
Total liabilities	711,143	566,618		574,744		121,744
Total mezzanine equity	161,381	161,392		161,122		
Total equity	$ 326,663	$ 716,403		$ 730,903		$

(1) Includes cash expenses of commitment fees and agency fees and non-cash amortization of debt issuance costs.

(2) Please read “—Non-GAAP Financial Measures” below for the definitions of EBITDA and Adjusted EBITDA and a reconciliation of EBITDA and Adjusted EBITDA to our most directly comparable financial measure, calculated and presented in accordance with generally accepted accounting principles in the United States (“GAAP”).

(3) Net of proceeds from the sale of assets of $1.0 million and $0.1 million for the years ended December 31, 2013 and December 31, 2012, respectively, and $0.1 million for the six months ended June 30, 2013.

Non-GAAP Financial Measures

EBITDA and Adjusted EBITDA are non-GAAP supplemental financial measures used by our management and by external users of our financial statements such as investors, commercial banks, research analysts, and others, to assess:

- our ability to make distributions to unitholders;
- the financial performance of our assets without regard to financing methods, capital structure, or historical cost basis;
- the ability of our assets to generate sufficient cash to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies and partnerships in our industry, without regard to financing or capital structure; and
- the feasibility of acquisitions and other capital expenditures and the overall rates of return on investment opportunities.

We define EBITDA as net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, impairment of oil and natural gas properties, and accretion of asset retirement obligations ("ARO"). We define Adjusted EBITDA as EBITDA further adjusted for unrealized gains/losses on derivative instruments and non-cash equity-based compensation.

EBITDA and Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, income from operations, cash flows from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP as measures of our operating performance or liquidity. EBITDA and Adjusted EBITDA do not include changes in working capital, capital expenditures, and other items that are set forth in a cash flow statement presentation of our operating, investing, and financing activities. Any measures that exclude these elements have material limitations. Our computation of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies.

Table of Contents

The following table presents a reconciliation of EBITDA and Adjusted EBITDA to the most directly comparable GAAP financial measure for the periods indicated.

	Black Stone Minerals, L.P. Predecessor Historical				Black Stone Minerals, L.P. Pro Forma	
	Year Ended December 31,		Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	2012	2013	2013	2014	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Reconciliation of EBITDA and Adjusted EBITDA to net income:						
Net income	$151,810	$168,963	$80,446	$131,995	$176,672	$137,012
Add:						
Depletion, depreciation and amortization	104,059	102,442	51,090	46,993	102,442	46,993
Impairment of oil and natural gas properties	62,987	57,109	27,630	—	57,109	—
Accretion of asset retirement obligations	608	588	307	295	588	295
Interest expense(1)	9,166	11,342	4,747	6,852	3,633	1,835
EBITDA	328,630	340,444	164,220	186,135	340,444	186,135
Add:						
Unrealized loss on commodity derivative instruments	10,697	7,350	328	5,400	7,350	5,400
Equity-based compensation expense(2)	7,247	6,782	3,394	5,654	6,782	5,654
Adjusted EBITDA	$346,574	$354,576	$167,942	$197,189	$354,576	$197,189

(1) Includes cash expenses of commitment fees and agency fees and non-cash amortization of debt issuance costs.
(2) Represents compensation expense that is settled in common units.

RISK FACTORS

Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should carefully consider the following risk factors together with all of the other information included in this prospectus in evaluating an investment in our common units. If any of the following risks were to occur, our business, financial condition, results of operations and cash available for distribution could be materially adversely affected. In that case, we might not be able to make distributions on our common units, the trading price of our common units could decline, and you could lose all or part of your investment.

Risks Related to Our Business

We may not have sufficient available cash to pay any quarterly distribution on our common units.

We may not have sufficient available cash each quarter to enable us to pay any distributions to our common unitholders. Our preferred unitholders have priority with respect to rights to share in distributions over our common unitholders. Furthermore, our partnership agreement does not require us to pay distributions to our common unitholders on a quarterly basis or otherwise. Available cash for each quarter will be determined by the board of directors of our general partner. Our expected aggregate annual distribution amount for the year ending December 31, 2015 is based on the assumptions set forth in "Cash Distribution Policy and Restrictions on Distributions—Estimated Cash Available for Distribution for the Year Ending December 31, 2015—Assumptions and Considerations." If our assumptions prove to be inaccurate, our actual distributions for the year ending December 31, 2015 may be significantly lower than our forecasted distributions, or we may not be able to pay a distribution at all. The amount of cash we have to distribute each quarter principally depends upon the amount of revenues we generate, which are largely dependent upon the prices that our operators realize from the sale of oil and natural gas. The actual amount of cash we will have to distribute each quarter will be reduced by principal and interest payments on our outstanding debt, working-capital requirements, and other cash needs. In addition, we may restrict distributions, in whole or in part, to fund acquisitions and participation in working interests. If we do not retain cash for replacement capital expenditures in amounts necessary to maintain our asset base, our cash available for distribution will decrease over time. The board of directors of our general partner may in the future decide to withhold from cash available for distribution amounts for our capital expenditures which may have an adverse impact on the cash available for distribution in the quarter in which amounts are withheld.

For a description of additional restrictions and factors that may affect our ability to make cash distributions, please read "Cash Distribution Policy and Restrictions on Distributions" and "Description of Our Preferred Units—Distributions."

The assumptions underlying the forecast of cash available for distribution that we include in "Cash Distribution Policy and Restrictions on Distributions" may prove inaccurate and are subject to significant risks and uncertainties, which could cause actual results to differ materially from our forecasted results.

The forecast of cash available for distribution set forth in "Cash Distribution Policy and Restrictions on Distributions" includes our forecast of our results of operations, Adjusted EBITDA and cash available for distribution for the year ending December 31, 2015. The assumptions underlying the forecast may prove inaccurate and are subject to significant risks and uncertainties that could cause actual results to differ materially from our forecasted results. If our actual results are significantly below forecasted results, or if our expenses are greater than forecasted, we may not be able to pay the forecasted annual distribution, which may cause the market price of our common units to decline materially.

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flow and not our profitability, which may prevent us from making cash distributions during periods when we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods in which we record net losses for financial accounting purposes and may be unable to make cash distributions during periods in which we record net income.

***The amount of our quarterly cash distributions, if any, may vary significantly, both quarterly and annually and will be directly dependent on the performance of our business. We will not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time and could make no distribution with respect to any particular quarter*.**

Investors who are looking for an investment that will pay regular and predictable quarterly distributions should not invest in our common units. Our future business performance may be volatile, and our cash flows may be unstable. Please read "—The volatility of oil and natural gas prices due to factors beyond our control greatly affects our financial condition, results of operations, and cash available for distribution." We will not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time. Because our quarterly distributions will significantly correlate to the cash we generate each quarter after payment of our fixed and variable expenses, future quarterly distributions paid to our common unitholders will vary significantly from quarter to quarter and may be zero.

The volatility of oil and natural gas prices due to factors beyond our control greatly affects our financial condition, results of operations, and cash available for distribution.

Our revenues, operating results, cash available for distribution and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty, and a variety of additional factors that are beyond our control, including:

- the domestic and foreign supply of and demand for oil and natural gas;
- market expectations about future prices of oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the cost of exploring for, developing, producing, and delivering oil and natural gas;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing regions, including the Middle East, Africa, South America, and Russia;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and natural disasters;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East;

- the proximity, cost, availability, and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. For example, during the past five years, the spot price for West Texas Intermediate light sweet crude oil, which we refer to as West Texas Intermediate, or WTI, has ranged from a low of $59.62 per barrel, or Bbl, in 2009 to a high of $113.39 per Bbl in 2011. The Henry Hub spot market price of natural gas has ranged from a low of $1.82 per million British thermal units, or MMBtu, in 2012 to a high of $8.15 per MMBtu in 2014. During 2013, West Texas Intermediate prices ranged from $86.65 to $110.62 per Bbl and the Henry Hub spot market price of natural gas ranged from $3.08 to $4.52 per MMBtu. On June 30, 2013, the West Texas Intermediate spot price for crude oil was $96.36 per Bbl and the Henry Hub spot market price of natural gas was $3.57 per MMBtu. On June 30, 2014, the West Texas Intermediate spot price for crude oil was $106.07 per Bbl and the Henry Hub spot market price of natural gas was $4.39 per MMBtu. Any prolonged substantial decline in the price of oil and natural gas will likely have a material adverse effect on our financial condition, results of operations and cash available for distribution. We may use various derivative instruments in connection with anticipated oil and gas sales to minimize the impact of commodity price fluctuations. However, we cannot always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, or our hedges are not effective, our results of operations and financial position may be diminished.

In addition, lower oil and natural gas prices may also reduce the amount of oil and natural gas that can be produced economically by our operators. This may result in our having to make substantial downward adjustments to our estimated proved reserves, which could negatively impact our borrowing base and our ability to fund our operations. If this occurs or if production estimates change or exploration or development results deteriorate, full cost accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Our operators could also determine during periods of low commodity prices to shut in or curtail production from wells on our properties. In addition, they could determine during periods of low commodity prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, they may abandon any well if they reasonably believe that the well can no longer produce oil or natural gas in commercially paying quantities.

Natural gas prices have declined substantially from historical highs and are expected to remain depressed for the foreseeable future. Approximately 74.2% of our 2013 production and 71.8% of our production in the first six months of 2014, on an MBoe basis, was natural gas. Any additional decreases in prices of natural gas may adversely affect our cash flow, results of operations, and financial position, perhaps materially.

Natural gas prices have declined from an average price at Henry Hub of $8.89 per MMBtu in 2008 to $3.73 per MMBtu in 2013. The reduction in prices has been caused by many factors, including increases in gas production and reserves from unconventional (shale) reservoirs, without an offsetting increase in demand. The expected increase in natural gas production, based on reports from the EIA, could cause the prices for natural gas to remain at current levels or fall to lower levels. If prices for natural gas continue to remain depressed for lengthy periods, we may be required to write down the value of our oil and natural gas properties, which may cause some of our undeveloped locations to no longer be economically viable. In addition, sustained low prices for natural gas will reduce the amounts we would otherwise have available to pay expenses, make distributions to our common unitholders and service our indebtedness.

Our failure to successfully identify, complete, and integrate acquisitions could adversely affect our growth, results of operations, and cash available for distribution.

We depend partly on acquisitions to grow our reserves, production, and cash flow. Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data, and other information, the results of which are often inconclusive and subject to various interpretations. The successful acquisition of properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- development plans;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, if applicable, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain financing. In addition, compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities, and increase our exposure to penalties or fines for non-compliance with additional legal requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired assets into our existing operations. The process of integrating acquired assets may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources.

No assurance can be given that we will be able to identify suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition, results of operations, and cash available for distribution. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our growth, results of operations, and cash available for distribution.

Any acquisitions of additional mineral and royalty interests that we complete will be subject to substantial risks.

Even if we do make acquisitions that we believe will increase our cash available for distribution, these acquisitions may nevertheless result in a decrease in our cash available for distribution. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, prices, revenues, capital expenditures, operating expenses, and costs;

- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses, or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- mistaken assumptions about the overall cost of equity or debt;
- our ability to obtain satisfactory title to the assets we acquire;
- an inability to hire, train, or retain qualified personnel to manage and operate our growing business and assets; and
- the occurrence of other significant changes, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation, or restructuring charges.

Title to the properties in which we have an interest may be impaired by title defects.

No assurance can be given that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

We depend on various unaffiliated operators for all of the exploration, development, and production on the properties underlying our mineral and royalty interests and non-operated working interests. Substantially all of our revenue is derived from the sale of oil and gas production from producing wells in which we own a royalty interest or a non-operated working interest. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of our operators to adequately and efficiently develop and operate our acreage could have an adverse effect on our results of operations.

Our assets consist of mineral and royalty interests and non-operated working interests. For the six months ended June 30, 2014, we received revenue from over 1,400 operators. The failure of our operators to adequately or efficiently perform operations or an operator's failure to act in ways that are in our best interests could reduce production and revenues. Our operators are often not obligated to undertake any development activities other than those required to maintain their leases on our acreage. In the absence of a specific contractual obligation, any development and production activities will be subject to their reasonable discretion. Our operators could determine to drill and complete fewer wells on our acreage than is currently expected. The success and timing of drilling and development activities on our properties, and whether the operators elect to drill any additional wells on our acreage, depends on a number of factors that will be largely outside of our control, including:

- the capital costs required for drilling activities by our operators, which could be significantly more than anticipated;
- the ability of our operators to access capital;
- prevailing commodity prices;
- the availability of suitable drilling equipment, production and transportation infrastructure, and qualified operating personnel;
- the operators' expertise, operating efficiency, and financial resources;
- approval of other participants in drilling wells;
- the operators' expected return on investment in wells drilled on our acreage as compared to opportunities in other areas;
- the selection of technology;

- the selection of counterparties for the marketing and sale of production; and
- the rate of production of the reserves.

The operators may elect not to undertake development activities, or may undertake these activities in an unanticipated fashion, which may result in significant fluctuations in our results of operations and cash available for distribution to our common unitholders. Sustained reductions in production by the operators on our properties may also adversely affect our results of operations and cash available for distribution.

We may experience delays in the payment of royalties and be unable to replace operators that do not make required royalty payments, and we may not be able to terminate our leases with defaulting lessees if any of the operators on those leases declare bankruptcy.

A failure on the part of the operators to make royalty payments gives us the right to terminate the lease, repossess the property, and enforce payment obligations under the lease. If we repossessed any of our properties, we would seek a replacement operator. However, we might not be able to find a replacement operator and, if we did, we might not be able to enter into a new lease on favorable terms within a reasonable period of time. In addition, the outgoing operator could be subject to a proceeding under title 11 of the United States Code (the “Bankruptcy Code”), in which case our right to enforce or terminate the lease for any defaults, including non-payment, may be substantially delayed or otherwise impaired. In general, in a proceeding under the Bankruptcy Code, the bankrupt operator would have a substantial period of time to decide whether to ultimately reject or assume the lease, which could prevent the execution of a new lease or the assignment of the existing lease to another operator. In the event that the operator rejected the lease, our ability to collect amounts owed would be substantially delayed, and our ultimate recovery may be only a fraction of the amount owed or nothing. In addition, if we are able to enter into a new lease with a new operator, the replacement operator may not achieve the same levels of production or sell oil or natural gas at the same price as the operator it replaced.

Acquisitions, funding our working-interest participation program, and our operators’ development activities of our leases will require substantial capital, and we and our operators may be unable to obtain needed capital or financing on satisfactory terms or at all.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in connection with the acquisition of mineral and royalty interests and participation in our working-interest participation program. To date, we have financed capital expenditures primarily with funding from cash generated by operations, limited borrowings under our credit facility and an issuance of equity securities.

In the future, we may restrict distributions to fund acquisitions and participation in our working interests but eventually we may need capital in excess of the amounts we retain in our business or borrow under our credit facility. We cannot assure you that we will be able to access external capital on terms favorable to us or at all. If we are unable to fund our capital requirements, we may be unable to complete acquisitions, take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our results of operation and cash available for distribution.

Most of our operators are also dependent on the availability of external debt and equity financing sources to maintain their drilling programs. If those financing sources are not available to the operators on favorable terms or at all, then we expect the development of our properties to be adversely affected. If the development of our properties is adversely affected, then revenues from our mineral and royalty interests and non-operated working interests may decline.

Unless we replace the oil and natural gas produced from our properties, our cash flow from operations and our ability to make distributions to our common unitholders could be adversely affected.

Producing oil and natural gas wells are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and our operators' production thereof and our cash flow and ability to make distributions are highly dependent on the successful development and exploitation of our current reserves. The production decline rates of our properties may be significantly higher than currently estimated if the wells on our properties do not produce as expected. We may also not be able to find, acquire, or develop additional reserves to replace the current and future production of our properties at economically acceptable terms, which would adversely affect our business, financial condition and results of operations, and cash available for distribution to our common unitholders.

We either have little or no control over the timing of future drilling with respect to our mineral and royalty interests and non-operated working interests.

Our proved undeveloped reserves may not be developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations, and the decision to pursue development of a proved undeveloped drilling location will be made by the operator and not by us. The reserve data included in the reserve report of our engineer assume that substantial capital expenditures are required to develop the reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of the development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop our reserves, or decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

Project areas on our properties, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Project areas on our properties are in various stages of development, ranging from project areas with current drilling or production activity to project areas that have limited drilling or production history. If the wells in the process of being completed do not produce sufficient revenues or if dry holes are drilled, our financial condition, results of operations, and cash available for distribution may be adversely affected.

Our operators' identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

The ability of our operators to drill and develop identified potential drilling locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs, drilling results, and the availability of water. Further, our operators' identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. The use of technologies and the study of producing fields in the same area will not enable our operators to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, our operators may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If our operators drill additional wells that they identify as dry holes in current and future drilling locations, their drilling success rate may decline and materially harm their business as well as ours.

We cannot assure you that the analogies our operators draw from available data from the wells on our acreage, more fully explored locations or producing fields will be applicable to their drilling locations. Further, initial production rates reported by our or other operators in the areas in which our reserves are located may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations our operators have identified will ever be drilled or if our operators will be able to produce oil or natural gas from these or any other potential drilling locations. As such, the actual drilling activities of our operators may materially differ from those presently identified, which could adversely affect our business, results of operation, and cash available for distribution.

The unavailability, high cost, or shortages of rigs, equipment, raw materials, supplies, or personnel may restrict or result in increased costs for operators related to developing and operating our properties.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, and personnel. When shortages occur, the costs and delivery times of rigs, equipment, and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. In accordance with customary industry practice, our operators rely on independent third-party service providers to provide many of the services and equipment necessary to drill new wells. If our operators are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services, and production equipment could delay or restrict our operators' exploration and development operations, which in turn could have a material adverse effect on our financial condition, results of operations, and cash available for distribution.

The marketability of oil and natural gas production is dependent upon transportation, pipelines, and refining facilities, which neither we nor many of our operators control. Any limitation in the availability of those facilities could interfere with our or our operators' ability to market our or our operators' production and could harm our business.

The marketability of our or our operators' production depends in part on the availability, proximity, and capacity of pipelines, tanker trucks, and other transportation methods, and processing and refining facilities owned by third parties. The amount of oil that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage, or lack of available capacity on these systems, tanker truck availability, and extreme weather conditions. Also, the shipment of our or our operators' oil and natural gas on third-party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we or our operators are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation, processing, or refining-facility capacity could reduce our or our operators' ability to market oil production and have a material adverse effect on our financial condition, results of operations, and cash available for distribution. Our or our operators' access to transportation options and the prices we or our operators receive can also be affected by federal and state regulation—including regulation of oil production and transportation, and pipeline safety—as well by general economic conditions and changes in supply and demand. In addition, the third parties on whom we or our operators rely for transportation services are subject to complex federal, state, tribal, and local laws that could adversely affect the cost, manner, or feasibility of conducting our business.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries, and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates, and the timing of development expenditures may be incorrect. Our historical estimates of proved reserves and related valuations as of December 31, 2013, were prepared by Pressler Petroleum Consultants, Inc. ("Pressler"), a third-party petroleum engineering firm, which conducted a detailed well-by-well review of all our properties for the period covered by its reserve report using information provided by us as well as publicly available production information. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing, and production. Also, certain assumptions regarding future oil and natural gas prices, production levels, and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves and future net cash flows. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that are ultimately recovered being different from our reserve estimates.

The estimates of reserves as of December 31, 2013 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the year ended December 31, 2013, in accordance with the SEC guidelines applicable to reserve estimates for those periods. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy, and energy-generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations, and cash available for distribution.

We rely on a few key individuals whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of individuals. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our executive team could disrupt our business. Further, we do not maintain “key person” life insurance policies on any of our executive team or other key personnel. As a result, we are not insured against any losses resulting from the death of these key individuals.

The results of exploratory drilling in shale plays will be subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operators use the latest drilling and completion techniques in their operations, and these techniques come with inherent risks. When drilling horizontal wells, operators risk not landing the well bore in the desired drilling zone and straying from the desired drilling zone. When drilling horizontally through a formation, operators risk being unable to run casing through the entire length of the well bore and being unable to run tools and other equipment consistently through the horizontal well bore. Risks that our operators face while completing wells include being unable to fracture stimulate the planned number of stages, to run tools the entire length of the well bore during completion operations, and to clean out the well bore after completion of the final fracture stimulation stage. In addition, to the extent our operators engage in horizontal drilling, those activities may adversely affect their ability to successfully drill in identified vertical drilling locations. Furthermore, certain of the new techniques that our operators may adopt, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before these wells begin producing. The results of drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently our operators will be less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our operators’ drilling results are weaker than anticipated or they are unable to execute their drilling program on our properties because of capital constraints, lease expirations, access to gathering systems, or declines in natural gas and oil prices, our operating and financial results in these areas may be lower than we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline and our results of operations and cash available for distribution could be adversely affected.

Oil and natural gas operations are subject to various governmental laws and regulations. Compliance with these laws and regulations can be burdensome and expensive, and failure to comply could result in significant liabilities, which could reduce our cash available for distribution.

Operations on the properties in which we hold interests are subject to various federal, state, and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include drilling operations, production and distribution activities, discharges or releases of pollutants or wastes, plugging and abandonment of wells, maintenance and decommissioning of other facilities, the spacing of wells, unitization and pooling of properties, and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and natural gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof, and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state, and local laws and regulations primarily relating to protection of human health and safety and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, or criminal penalties, permit revocations, requirements for additional pollution controls, and injunctions limiting, or prohibiting some or all of our operations. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management.

Laws and regulations governing exploration and production may also affect production levels. Our operators must comply with federal and state laws and regulations governing conservation matters, including:

- provisions related to the unitization or pooling of the oil and natural gas properties;
- the establishment of maximum rates of production from wells;
- the spacing of wells;
- the plugging and abandonment of wells; and
- the removal of related production equipment.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline-safety laws and regulations, compliance with which may require increased capital costs on the part of operators and third-party downstream natural gas transporters.

Our operators must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the operators of our properties are shippers on interstate pipelines, they must comply with the tariffs of those pipelines and with federal policies related to the use of interstate capacity.

Our operators may be required to make significant expenditures to comply with the governmental laws and regulations described above. We believe the trend of more expansive and stricter environmental legislation and regulations will continue. Please read “Business—Regulation” for a description of the laws and regulations that affect our operators and that may affect us. These and other potential regulations could increase the operating costs of our operators and delay production, which could reduce the amount of cash available for distribution to our common unitholders.

Louisiana mineral servitudes are subject to reversion to the surface owner after ten years' nonuse.

We own mineral servitudes covering several hundred thousand acres in Louisiana. A mineral servitude is created in Louisiana when the mineral rights are separated from the ownership of the surface, whether by sale or reservation. These mineral servitudes, once created, are subject to a ten-year prescription of nonuse. During the ten-year period, the mineral-servitude owner has to conduct good-faith operations on the servitude for the discovery and production of minerals, or the mineral servitude "prescribes," and the mineral rights associated with that servitude revert to the surface owner. A good-faith operation for the discovery and production of minerals, even one resulting in a dry hole, conducted within the ten-year period will interrupt the prescription of nonuse and restart the running of the ten-year prescriptive period. If the operation results in production, prescription is interrupted as long as the production continues or operations are conducted in good faith to secure or restore production. If any of our mineral servitudes are prescribed by operation of Louisiana law, our operating results may be adversely affected.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs, additional operating restrictions or delays, and fewer potential drilling locations.

Our operators engage in hydraulic fracturing. Hydraulic fracturing is a common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand, and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The federal Safe Drinking Water Act ("SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing is generally exempt from regulation under the UIC program, and the hydraulic-fracturing process is typically regulated by state oil and natural gas commissions. The Environmental Protection Agency ("EPA"), however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program and that these wells are required to obtain "Class II" UIC permits. In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on its proposed development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. Moreover, the EPA is developing effluent-limitation guidelines that may impose federal pre-treatment standards on all oil and natural gas operators transporting wastewater associated with hydraulic-fracturing activities to publicly owned treatment works for disposal. The EPA plans to propose these standards within the next year.

Further, in April 2012, the EPA published final rules that subject all oil and natural gas operations (production, processing, transmission, storage, and distribution) to regulation under the New Source Performance Standards ("NSPS") and the National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs. These rules became effective in October 2012 and include NSPS standards for completions of hydraulically fractured gas wells. The standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with restrictions on the flaring of gas not sent to the gathering line. The standards are applicable to newly drilled and fractured wells and wells that are refractured on or after January 1, 2015. Other areas related to federal regulation of hydraulic fracturing include the U.S. Department of the Interior's revised proposed rule, issued in May 2013, that would update existing regulation of hydraulic-fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The results of these studies could spur initiatives to further regulate hydraulic-fracturing under the SDWA or other regulatory authorities. The EPA is currently evaluating the potential impacts of hydraulic-fracturing on drinking water resources. The White House Council on Environmental Quality is conducting an administration-wide review of hydraulic fracturing practices. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shale formations by means of hydraulic fracturing and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Several states, including Texas, have adopted or are considering adopting regulations that could restrict or prohibit hydraulic fracturing in certain circumstances or require the disclosure of the composition of hydraulic-fracturing fluids. For example, the Texas Railroad Commission has adopted rules and regulations requiring that well operators disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act to state regulators and on a public internet website. We expect our operators to use hydraulic fracturing extensively in connection with the development and production of our oil and natural gas properties, and any increased federal, state, or local regulation of hydraulic fracturing could reduce the volumes of oil and natural gas that our operators can economically recover, which could materially and adversely affect our revenues and results of operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where our operators conduct operations, our operators may incur substantial costs to comply with these requirements, which may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from the drilling of wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, use of water, and the potential for impacts to surface water, groundwater, and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic-fracturing practices. If new laws or regulations are adopted that significantly restrict hydraulic fracturing, those laws could make it more difficult or costly for our operators to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, fracturing activities on our properties could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, and also to attendant permitting delays and potential increases in costs. Legislative changes could cause operators to incur substantial compliance costs. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas that our operators produce.

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established on a case-by-case basis. These EPA rulemakings could adversely affect operations on our properties and restrict or delay the ability of our operators to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include operations on certain of our properties.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our operators' equipment and operations could require them to incur costs to reduce emissions of GHGs associated with their operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas produced from our properties. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states, as well as state and local climate change initiatives, could adversely affect the oil and natural gas industry, and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, and other climatic events; if any of these effects were to occur, they could have a material adverse effect on our properties and operations.

Operating hazards and uninsured risks may result in substantial losses to us or our operators, and any losses could adversely affect our results of operations and cash available for distribution.

We may be secondarily liable for damage to the environment caused by our operators. The operations of our operators will be subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe, or pipeline failures, abnormally pressured formations, casing collapses, and environmental hazards such as oil spills, gas leaks and ruptures, or discharges of toxic gases. In addition, their operations will be subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage, or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to our operators due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations, and repairs required to resume operations.

In accordance with what we believe to be customary industry practice, we maintain insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash available for distribution. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

We may not have coverage if we are unaware of a sudden and accidental pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We do not have, and do not intend to obtain, coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations, and cash available for distribution.

Cyber attacks could significantly affect us.

Cyber attacks on businesses have escalated in recent years. We rely on electronic systems and networks to control and manage our business and have multiple layers of security to mitigate risks of cyber attack. If, however, we were to experience an attack and our security measures failed, the potential consequences to our businesses and the communities in which we operate could be significant.

Risks Inherent in an Investment in Us

The board of directors of our general partner will adopt a policy to distribute a substantial majority of the available cash we generate each quarter, which could limit our ability to grow and make acquisitions.

As a result of our cash distribution policy, we will have limited cash available to reinvest in our business or to fund acquisitions, and we will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and growth capital expenditures. If we are unable to finance growth externally, our distribution policy will significantly impair our ability to grow.

If we issue additional units in connection with any acquisitions or growth capital expenditures or as in-kind distributions, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. Other than limitations restricting our ability to issue units ranking senior or on a parity with our preferred units, there are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units with respect to distributions. If we incur debt to finance our growth, our interest expense will increase, reducing the available cash that we have to distribute to our unitholders. Please read “Cash Distribution Policy and Restrictions on Distributions.”

The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all. If we make distributions, our preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our preferred units are outstanding.

In connection with the closing of this offering, the board of directors of our general partner will adopt a cash distribution policy pursuant to which we will distribute a substantial majority of the available cash we generate each quarter to our unitholders of record. However, the board of directors of our general partner may change this policy at any time at its discretion and could elect not to pay distributions for one or more quarters. Please read “Cash Distribution Policy and Restrictions on Distributions.”

In addition, our partnership agreement does not require us to pay any distributions at all on our common units. Accordingly, investors are cautioned not to place undue reliance on the permanence of a policy in making an investment decision. Any modification or revocation of our cash distribution policy could substantially reduce or eliminate the amounts of distributions to our unitholders. The amount of distributions we make, if any, and the decision to make any distribution at all will be determined by the board of directors of our general partner. If we make distributions, our preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our preferred units are outstanding. Please read “Description of Our Preferred Units—Distributions.”

Our partnership agreement eliminates the fiduciary duties that might otherwise be owed to the partnership and its partners by our general partner and its directors and executive officers under Delaware law.

Our partnership agreement contains provisions that eliminate the fiduciary duties that might otherwise be owed by our general partner and its directors and executive officers. For example, our partnership agreement provides that our general partner and its directors and executive officers have no duties to the partnership or its partners except as expressly set forth in the partnership agreement. In place of default fiduciary duties, our partnership agreement imposes a contractual standard requiring our general partner and its directors and executive officers to act in good faith, meaning they cannot cause the general partner to take an action that they subjectively believe is adverse to our interests. Such contractual standards allow our general partner and its directors and executive officers to manage and operate our business with greater flexibility and to subject the actions and determinations of our general partner and its directors and executive officers to lesser legal or judicial scrutiny than would be the case if state law fiduciary standards were applicable.

Our partnership agreement restricts the situations in which remedies may be available to our unitholders for actions taken that might constitute breaches of duty under applicable Delaware law and breaches of the contractual obligations in our partnership agreement.

Our partnership agreement restricts the potential liability of our general partner and its directors and executive officers to our unitholders. For example, our partnership agreement provides that our general partner and its directors and executive officers will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in willful misconduct or fraud or, with respect to any criminal conduct, with the knowledge that its conduct was unlawful.

Unitholders are bound by the provisions of our partnership agreement, including the provisions described above. Please read "Fiduciary Duties."

Our partnership agreement restricts the voting rights of unitholders owning 15% or more of our common units, subject to certain exceptions.

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person or group that owns 15% or more of any class of units then outstanding, other than the initial limited partners in our predecessor, their transferees and persons who entitled to vote acquired those units with the prior approval of the board of directors of our general partner, may not vote on any matter. In addition, solely with respect to the election of directors, our partnership agreement provides that (x) our general partner and the partnership will not be their units, if any, and (y) if at any time any person or group beneficially owns 15% or more of the outstanding partnership securities of any class then outstanding and otherwise entitled to vote, then none of the partnership securities owned by such person or group of the outstanding partnership securities of the applicable class may be voted, and in each case, the foregoing units will not be counted when calculating the required votes for a matter and will not be deemed to be outstanding for purposes of determining a quorum for a meeting. These common units will not be treated as a separate class of partnership securities for purposes of our partnership agreement or the Delaware Revised Uniform Limited Partnership Act. Notwithstanding the foregoing, the board of directors of our general partner may, by action specifically referencing votes for the election of directors, determine that the limitation set forth in clause (y) above will not apply to a specific person or group. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the ability of our common unitholders to influence the manner or direction of management.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions to you.

We are a partnership holding company, and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws, and other laws and regulations.

Unitholders may not have limited liability if a court finds that unitholder action constitutes participation in control of our business.

The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could have unlimited liability for our obligations if a court or government agency determined that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to elect the directors of our general partner, to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constituted participation in "control" of our business.

Unitholders may have liability to repay distributions and in certain circumstances may be personally liable for the obligations of the partnership.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Liabilities to partners on account of their partnership interests and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted by Section 17-607 of the Delaware Act.

A limited partner that participates in the control of our business within the meaning of the Delaware Act may be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. Please read "The Partnership Agreement—Limited Liability."

Increases in interest rates may cause the market price of our common units to decline.

An increase in interest rates may cause a corresponding decline in demand for equity investments in general, and in particular, for yield-based equity investments such as our common units. Any such increase in interest rates or reduction in demand for our common units resulting from other relatively more attractive investment opportunities may cause the trading price of our common units to decline.

Common unitholders will incur immediate and substantial dilution in net tangible book value per common unit.

The assumed initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover page of this prospectus) exceeds our pro forma net tangible book value of $ per common unit. Based on the assumed initial public offering price of $ per common unit, common unitholders will incur immediate and substantial dilution of $ per common unit. This dilution results primarily because the assets contributed to us by our predecessor are recorded at their historical cost in accordance with GAAP and not their fair value. Please read "Dilution."

We may issue additional common units and other equity interests without common unitholder approval, which would dilute holders of common units. However, our partnership agreement does not authorize us to issue units ranking senior to or at parity with our preferred units without preferred unitholder approval.

Under our partnership agreement, we are authorized to issue an unlimited number of additional interests, including common units, without a vote of the unitholders other than, in certain instances, approval of holders of our preferred units. Our issuance of additional common units or other equity interests of equal or senior rank will have the following effects:

- the proportionate ownership interest of common unitholders in us immediately prior to the issuance will decrease;
- the amount of cash distributions on each common unit may decrease;

- the ratio of our taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of the common units may decline.

However, our partnership agreement does not authorize us to issue securities having preferences or rights with priority over or on a parity with the preferred units with respect to rights to share in distributions, redemption obligations or redemption rights without preferred unitholder approval. Please read "The Partnership Agreement—Issuance of Additional Partnership Interests" and "Description of Our Preferred Units."

The market price of our common units could be adversely affected by sales of substantial amounts of our common units in the public or private markets.

After this offering, we will have common units outstanding, including the common units that we are selling in this offering that may be resold in the public market immediately. All of the common units that are issued to our directors, executive officers, and other affiliates will be subject to resale restrictions under a 180-day lock-up agreement with the underwriters. Each of the lock-up agreements with the underwriters may be waived in the discretion of certain of the underwriters. Sales by holders of a substantial number of our common units in the public markets following this offering, or the perception that these sales might occur, could have a material adverse effect on the price of our common units or impair our ability to obtain capital through an offering of equity securities. In addition, we have agreed to provide registration rights to our directors, executive officers and other affiliates. Under our partnership agreement, certain of our affiliates have registration rights relating to the offer and sale of any units that they hold. Please read "Units Eligible for Future Sale."

There is no existing market for our common units, and a trading market that will provide you with adequate liquidity may not develop. The price of our common units may fluctuate significantly, and unitholders could lose all or part of their investment.

Prior to this offering, there has been no public market for the common units. After this offering, there will be only publicly traded common units. We do not know the extent to which investor interest will lead to the development of a trading market or how liquid that market might be. Unitholders may not be able to resell their common units at or above the initial public offering price. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The initial public offering price for our common units will be determined by negotiations between us and the representatives of the underwriters and may not be indicative of the market price of the common units that will prevail in the trading market. The market price of our common units may decline below the initial public offering price. The market price of our common units may also be influenced by many factors, some of which are beyond our control, including those described elsewhere in these risk factors.

We will incur increased costs as a result of being a publicly traded partnership.

We have no history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting, and other expenses that we did not incur prior to this offering. In addition, the Sarbanes-Oxley Act and the Dodd-Frank Act of 2010, as well as rules implemented by the SEC and the NYSE, require, or will require, publicly traded entities to adopt various corporate governance practices that will further increase our costs. Before we are able to make distributions to our unitholders, we must first pay our expenses, including the costs of being a publicly traded partnership and other operating expenses. As a result, the amount of cash we have available for distribution to our unitholders will be reduced by our expenses, including the costs associated with being a publicly traded partnership.

Following this offering, we will become subject to the public reporting requirements of the Exchange Act. We expect these requirements will increase our legal and financial compliance costs. For example, as a result of becoming a publicly traded partnership, we are required to have at least three independent directors and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal control over financial reporting.

We estimate that we will incur approximately $ million of incremental costs per year associated with being a publicly traded partnership; however, it is possible that our actual incremental costs of being a publicly traded partnership will be higher than we currently estimate.

For as long as we are an emerging growth company, we will not be required to comply with certain disclosure requirements, including those relating to accounting standards, disclosure about our executive compensation and internal control auditing requirements that apply to other public companies.

We are classified as an "emerging growth company" under Section 2(a)(19) of the Securities Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, we will not be required to comply with certain requirements that other public companies are required to comply with. Among other things, we will not be required to:

- provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act;
- comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; or
- provide certain disclosure regarding executive compensation required of larger public companies.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Upon the completion of this offering, we will become subject to the public reporting requirements of the Exchange Act. We prepare our financial statements in accordance with GAAP, but our internal controls over financial reporting may not currently meet all standards applicable to companies with publicly traded securities. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud, and operate successfully as a publicly traded partnership. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future, or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act. For example, Section 404 will require us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. We must comply with Section 404 (except for the requirement for an auditor's attestation report) beginning with our fiscal year ending December 31, 2016. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common units.

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

We intend to apply to list our common units on the NYSE. Because we will be a publicly traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. In addition, because we are a publicly traded partnership, the NYSE does not require us to obtain unitholder approval prior to certain unit issuances. Accordingly, unitholders will not have the same protections afforded to stockholders of certain corporations that are subject to all of the NYSE's corporate governance requirements. Please read "Management."

Our partnership agreement includes exclusive forum, venue, and jurisdiction provisions. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions, or proceedings, and submitting to the exclusive jurisdiction of Delaware courts. Our partnership agreement also provides that any limited partner holding common units bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with an unsuccessful action.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue, and jurisdiction provisions designating Delaware courts as the exclusive venue for all claims, suits, actions, and proceedings arising out of or relating in any way to the partnership agreement, brought in a derivative manner on behalf of the partnership, asserting a claim of breach of a fiduciary or other duty owed by any director, officer, or other employee of the partnership or the general partner, or owed by the general partner to the partnership or the partners, asserting a claim arising pursuant to any provision of the Delaware Act or asserting a claim governed by the internal affairs doctrine. In addition, if any person holding common units brings any of the aforementioned claims, suits, actions, or proceedings and the person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then the person shall be obligated to reimburse us and our affiliates for all fees, costs, and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with a claim, suit, action, or proceeding. Please read "The Partnership Agreement—Applicable Law; Forum, Venue, and Jurisdiction." By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions, or proceedings and submitting to the exclusive jurisdiction of Delaware courts. If a dispute were to arise between a limited partner and us or our officers, directors, or employees, the limited partner may be required to pursue its legal remedies in Delaware, which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment.

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to permit the general partner to redeem the units of certain common unitholders.

Our general partner may amend our partnership agreement, as it determines necessary or advisable, to obtain proof of the U.S. federal income tax status or the nationality, citizenship, or other related status of our limited partners (and their owners, to the extent relevant) and to permit our general partner to redeem the common units held by any person (i) whose nationality, citizenship, or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (ii) who fails to comply with the procedures established to obtain that proof. The redemption price will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption. Please read "The Partnership Agreement—Non-Taxpaying Holders; Redemption" and "The Partnership Agreement—Non-Citizen Assignees; Redemption."

Common unitholders who are not "Eligible Holders" will not be entitled to receive distributions on or allocations of income or loss on their common units, and their common units will be subject to redemption.

In order to comply with U.S. laws with respect to the ownership of interests in oil and natural gas leases on federal lands, we will adopt certain requirements regarding those investors who may own our common units. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and natural gas leases on federal lands. As of the date hereof, Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if this association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding or control in a corporation organized under the laws of the United States or of any state thereof and only for so long as the alien is not from a country that the United States federal government regards as denying similar privileges to citizens or corporations of the United States. Common unitholders who are not persons or entities who meet the requirements to be an Eligible Holder will not be entitled to receive distributions or allocations of income and loss on their units and they run the risk of having their units redeemed by us at the lower of their purchase price cost or the then-current market price. The redemption price will be paid in cash or by delivery of a promissory note, as determined by our general partner.

For the avoidance of doubt, we will not adopt Eligible Holder requirements regarding those investors who own our preferred units.

Tax Risks to Common Unitholders

In addition to reading the following risk factors, you should read "Material U.S. Federal Income Tax Consequences" for a more complete discussion of the expected material federal income tax consequences of owning and disposing of common units.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, then our cash available for distribution to unitholders could be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, we have not requested, and do not plan to request, a ruling from the IRS on this or any other matter affecting us. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, or deductions would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you would be substantially reduced. In addition, changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, and other forms of taxation. Imposition of any of those taxes may substantially reduce the cash available for distribution to you. Therefore, treatment of us as a corporation or the assessment of a material amount of entity-level taxation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial, or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative, or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. One legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will be reintroduced or will ultimately be enacted. Any changes could negatively impact the value of an investment in our common units. Any modification to U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the qualifying income requirement to be treated as a partnership for U.S. federal income tax purposes. For a discussion of the importance of our treatment as a partnership for federal income tax purposes, please read "Material U.S. Federal Income Tax Consequences—Taxation of the Partnership—Partnership Status" for a further discussion.

If the IRS were to contest the federal income tax positions we take, it may adversely affect the market for our common units, and the costs of any contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the conclusions of our counsel expressed in this prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take. A court may not agree with some or all of our counsel's conclusions or positions we take. Any contest with the IRS may materially and adversely affect the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

Even if a unitholder does not receive any cash distributions from us, a unitholder will be required to pay taxes on its share of our taxable income.

You will be required to pay federal income taxes and, in some cases, state and local income taxes, on your share of our taxable income, whether or not you receive cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax due from you with respect to that income.

Tax gain or loss on disposition of our common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell your units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation and depletion recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Units—Recognition of Gain or Loss."

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, a portion of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, may be unrelated business taxable income and may be taxable to them. Distributions to non-U.S. persons will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-

U.S. persons, and each non-U.S. person may be required to file United States federal tax returns and pay tax on their share of our taxable income if it is treated as effectively connected income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units. Please read “Material U.S. Federal Income Tax Consequences—Tax-Exempt Organizations and Other Investors.”

We will treat each purchaser of common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of our common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. Our counsel is unable to opine as to the validity of this approach. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns. Please read “Material U.S. Federal Income Tax Consequences—Tax Consequences of Unit Ownership—Section 754 Election” for a further discussion of the effect of the depreciation and amortization positions we adopted.

We will prorate our items of income, gain, loss, and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss, and deduction among our unitholders.

We will prorate our items of income, gain, loss, and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, our counsel is unable to opine as to the validity of this method. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders. Please read “Material U.S. Federal Income Tax Consequences—Disposition of Units—Allocations Between Transferors and Transferees.”

A unitholder whose units are the subject of a securities loan (e.g., a loan to a “short seller” to cover a short sale of units) may be considered to have disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and could recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from this disposition. Moreover, during the period of the loan, any of our income, gain, loss, or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Our counsel has not rendered an opinion regarding the treatment of a unitholder where common units are loaned to a short seller to effect a short sale of common units. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, after our termination, we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. Please read "Material U.S. Federal Income Tax Consequences—Disposition of Units—Constructive Termination" for a discussion of the consequences of our termination for federal income tax purposes.

You may be subject to state and local taxes and return filing requirements in states where you do not live as a result of investing in our common units.

In addition to federal income taxes, you likely will be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance, or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in any of those jurisdictions. We will initially own assets and conduct business in several states, many of which impose a personal income tax and also impose income taxes on corporations and other entities. You may be required to file state and local income tax returns and pay state and local income taxes in these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements. As we make acquisitions or expand our business, we may own assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all U.S. federal, foreign, state, and local tax returns. Our counsel has not rendered an opinion on the foreign, state, or local tax consequences of an investment in our common units.

USE OF PROCEEDS

We intend to use the estimated net proceeds of approximately $ million from this offering (based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover page of this prospectus), after deducting the estimated underwriting discount and offering expenses payable by us, to repay all of the indebtedness outstanding under our credit facility and to fund future capital expenditures.

The net proceeds from any exercise of the underwriters' option to purchase additional common units (approximately $ million, if exercised in full, based on an assumed initial offering price of $ per common unit, the mid-point of the price range set forth on the cover of this prospectus, after deducting the estimated underwriting discount) will be used to fund future capital expenditures.

Borrowings under our credit facility were primarily made for the acquisition of properties and other general business purposes. As of June 30, 2014, we had borrowings outstanding of $453.0 million under our credit facility. Indebtedness under our credit facility bore interest at an average rate of approximately 2.4% during the six months ended June 30, 2014. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facility."

Affiliates of certain of our underwriters are lenders under our credit facility and, as such, may receive a portion of the proceeds from this offering. Please read "Underwriting—Relationships."

Table of Contents

CAPITALIZATION

The following table shows our cash and cash equivalents and capitalization as of June 30, 2014:

- on an actual basis for our predecessor; and
- on a pro forma basis to reflect the offering and the other formation transactions described under "Summary—Formation Transactions and Structure" and the application of the net proceeds from this offering as described under "Use of Proceeds."

This table is derived from, and should be read together with, the historical and pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Summary—Formation Transactions and Structure," "Use of Proceeds" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	As of June 30, 2014	
	Black Stone Minerals, L.P. Predecessor Actual	Black Stone Minerals, L.P. Pro Forma
	(unaudited) (in thousands)	
Cash and cash equivalents	$ 12,789	$
Long-term debt	$ 453,000	—
Mezzanine equity:		
Black Stone Minerals Company, L.P.		
Preferred Units	161,122	—
Black Stone Minerals, L.P.		
Preferred Units	—	—
Equity:		
Black Stone Minerals Company, L.P.		
Common units	$ 726,958	$ —
Black Stone Minerals, L.P.		
Common units held by general partner	—	
Common units held by others	—	
Total common units	—	
Total equity	$ 726,958	$
Total capitalization	$ 1,341,080	$

Table of Contents

DILUTION

Dilution in net tangible book value per common unit represents the difference between the amount per common unit paid by purchasers of our common units in this offering and the pro forma net tangible book value per common unit immediately after this offering. Based on an initial public offering price of $ per common unit (the mid-point of the price range set forth on the cover page of this prospectus), and after deduction of the estimated underwriting discount and estimated offering expenses payable by us, our pro forma net tangible book value as of June 30, 2014 would have been approximately $ million, or $ per common unit. This represents an immediate pro forma dilution of $ per common unit to purchasers of common units in this offering. The following table illustrates this dilution on a per common unit basis:

Assumed initial public offering price per common unit		$
Pro forma net tangible book value per common unit before the offering(1)	$	
Increase in net tangible book value per common unit attributable to purchasers in the offering		
Less: Pro forma net tangible book value per common unit after the offering(2)		
Immediate dilution in net tangible book value per common unit to purchasers in the offering		

(1) Determined by dividing the pro forma net tangible book value of the contributed assets and liabilities by the number of our common units to be issued to the existing limited partners of BSMC in exchange for their limited partner interests in BSMC in connection with the merger of BSMC with and into our subsidiary.

(2) Determined by dividing our pro forma net tangible book value, after giving effect to the use of the net proceeds of the offering, by the total number of common units outstanding after this offering.

The following table sets forth the number of common units that we will issue and the total consideration contributed to us by the existing limited partners of BSMC and by the purchasers of our common units in this offering upon consummation of the transactions contemplated by this prospectus ($ in thousands).

	Units		Total Consideration	
	Number	Percent	Amount	Percent
Limited partners of BSMC prior to this offering(1)		%		%
Purchasers in this offering		%		%
Total		100%		100%

(1) Reflects the value of the assets to be contributed to us by the existing limited partners of BSMC, recorded at historical cost.

(2) Reflects the net proceeds of this offering, after deducting the underwriting discount and estimated offering expenses payable by us.

CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

You should read the following discussion of our cash distribution policy in conjunction with the specific assumptions included in this section. In addition, you should read "Forward-Looking Statements" and "Risk Factors" for information regarding statements that do not relate strictly to historical or current facts and certain risks inherent in our business. For additional information, you should refer to the historical financial statements of BSMC and our pro forma financial statements, included elsewhere in this prospectus.

General

Cash Distribution Policy

In connection with the closing of this offering, the board of directors of our general partner will adopt a policy pursuant to which we will distribute a substantial majority of the available cash we generate each quarter. Available cash for each quarter will be determined by the board of directors of our general partner following the end of that quarter. Our initial distribution will be $ per common unit on an annualized basis, which we forecast to represent approximately % of our available cash for the year ending December 31, 2015. It is our intent, for at least the next several years, to finance most of our acquisition and working-interest capital needs with the retained net proceeds from this offering, borrowings under our credit facility, and, in certain circumstances, proceeds from future equity and debt issuances. We may also borrow to make distributions to our unitholders where, for example, we believe that the distribution level is sustainable over the long term, but short-term factors may cause available cash from operations to be insufficient to pay distributions at the current level. The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time. Our partnership agreement does not require us to pay cash distributions on a quarterly or other basis. Please read "Risk Factors—Risks Inherent in an Investment in Us—The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to pay any distributions at all. If we make distributions, our preferred unitholders have priority with respect to rights to share in those distributions over our common unitholders for so long as our preferred units are outstanding."

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. Unlike a number of other master limited partnerships, we do not expect to initially retain cash from our operations for replacement capital expenditures, primarily due to our expectation that the development of existing plays and the discovery of new reserves will lead to increasing revenues for at least the next several years. We also intend to add reserves through acquisitions of mineral and royalty interests and through non-operated working-interest participation. We may restrict distributions, in whole or in part, to fund acquisitions and participation in working interests. If we do not retain cash for replacement capital expenditures in amounts necessary to maintain our asset base, our cash available for distribution per unit will decrease over time. The board of directors of our general partner may in the future decide to withhold from cash available for distribution amounts for our capital expenditures which may have an adverse impact on the cash available for distribution per unit in the quarter in which those amounts are withheld. To the extent that we do not withhold cash for capital expenditures in the future, a portion of our future cash available for distribution will represent a return of your capital.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that we will make cash distributions to our unitholders. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

- Our common unitholders have no contractual or other legal right to receive cash distributions from us on a quarterly or other basis, and if distributions are paid, common unitholders will receive distributions only to the extent the distribution amount exceeds distributions that are required to be paid to our preferred unitholders. The board of directors of our general partner will adopt a policy pursuant to which we will distribute to our unitholders each quarter a substantial majority of the available cash we generate each quarter, as determined quarterly by the board of directors, but it may change this policy at any time.

- Our credit facility contains certain financial tests and covenants that we must satisfy. If we are unable to satisfy the restrictions under our credit facility or any future debt agreements, we could be prohibited from making distributions notwithstanding our stated distribution policy.
- We will not have a minimum quarterly distribution or employ structures intended to maintain or increase quarterly distributions over time. Furthermore, none of our limited partner interests will be subordinate in right of distribution payment to the common units sold in this offering.
- Our general partner will have the authority to establish cash reserves for the prudent conduct of our business, and the establishment of, or increase in, those reserves could result in a reduction in cash distributions to our unitholders. Our partnership agreement does not limit the amount of cash reserves that our general partner may establish. Any decision to establish cash reserves made by our general partner will be binding on our unitholders.
- The distribution priority of our preferred units over the common units could result in us paying a full quarterly cash distribution on our preferred units and only a portion or none of the quarterly distribution on our outstanding common units if our available cash for such quarter is not sufficient to pay the distribution on all our outstanding units (common and preferred).
- Under Section 17-607 of the Delaware Act, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.
- We may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial, or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our outstanding debt, working capital requirements, and anticipated cash needs.

We expect to generally distribute a significant percentage of our cash from operations to our unitholders on a quarterly basis, after, among other things, the establishment of cash reserves. To fund our growth, we may eventually need capital in excess of the amounts we may retain in our business or borrow under our credit facility. To the extent efforts to access capital externally are unsuccessful, our ability to grow will be significantly impaired.

We expect to pay our distributions on our common units within 60 days of the end of each quarter. Our first distribution will be for the period from the closing of this offering through   , 2015.

Pro Forma Cash Available for Distribution for the Year Ended December 31, 2013 and the Twelve Months Ended June 30, 2014

The pro forma financial statements, upon which pro forma cash available for distribution is based, do not purport to present our results of operations had the transactions contemplated in this prospectus actually been completed as of the dates indicated. Furthermore, cash available for distribution is a cash concept, while our pro forma financial statements have been prepared on an accrual basis. We derived the amounts of pro forma cash available for distribution discussed above in the manner described in the table below. As a result, the amounts of pro forma cash available for distribution should only be viewed as a general indication of the amounts of cash available for distribution that we might have generated had we been formed and completed the transactions contemplated in this prospectus in earlier periods.

Following the completion of this offering, we estimate that we will incur $ million of incremental general and administrative expenses per year as a result of operating as a publicly traded partnership, which includes expenses associated with SEC reporting requirements, including annual and quarterly reports to

Table of Contents

unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NYSE listing, independent- auditor fees, legal fees, investor-relations activities, registrar and transfer agent fees, director-and-officer insurance, and additional compensation.

The following table illustrates, on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, the amount of cash that would have been available for distribution to our common unitholders, assuming that the transactions contemplated in this prospectus had been consummated on January 1, 2013 and July 1, 2013, respectively.

	Year Ended December 31, 2013	Twelve Months Ended June 30, 2014
	(unaudited) (in thousands)	
Revenues:		
Oil and condensate sales(1)	$ 252,742	$ 258,703
Natural gas and natural gas liquids sales(1)	184,868	200,173
Gain (loss) on commodity derivative instruments	(5,860)	(15,725)
Lease bonus and other income	31,809	44,130
Total revenues	$ 463,559	$ 487,281
Operating expenses:		
Lease operating expense and other	$ 21,316	$ 20,643
Production and ad valorem taxes	42,813	44,881
Depreciation, depletion, and amortization	102,442	98,345
Impairment of oil and natural gas properties(2)	57,109	29,479
General and administrative expense	59,501	60,524
Accretion of asset retirement obligations	588	576
Total operating expenses	$ 283,769	$ 254,448
Income from operations	$ 179,790	$ 232,833
Other income (expense):		
Interest and investment income	$ 90	$ 49
Interest expense(3)	(3,633)	(3,630)
Gain on sale of assets	18	—
Other income	407	1,077
Total other income (expense)	$ (3,118)	$ (2,504)
Pro forma net income	$ 176,672	$ 230,329
Adjustments to reconcile to pro forma Adjusted EBITDA:		
Add:		
Depletion, depreciation, and amortization	$ 102,442	$ 98,345
Impairment of oil and natural gas properties	57,109	29,479
Accretion of asset retirement obligations	588	576
Interest expense	3,633	3,630
Pro forma EBITDA(4)	$ 340,444	$ 362,359
Add:		
Unrealized loss on commodity derivative instruments	7,350	12,422
Equity-based compensation expense(5)	6,782	9,042
Pro forma Adjusted EBITDA(4)	$ 354,576	$ 383,823

	Year Ended December 31, 2013	Twelve Months Ended June 30, 2014
	(unaudited) (in thousands, except per unit data)	
Adjustments to reconcile to pro forma cash available for distribution:		
Add:		
Net proceeds from this offering to fund future capital expenditures		
Less:		
Incremental general and administrative expense(6)		
Cash interest expense	2,665	2,665
Capital expenditures(7)	195,631	131,631
Pro forma cash available for distribution	$	$
Less:		
Cash paid to noncontrolling interests	1,146	335
Preferred unit dividends(8)	15,742	15,736
Pro forma cash available for distribution on common units	$	$
Pro forma cash distribution per common unit		
Aggregate distributions of pro forma cash available for distribution to:		
Common units issued in this offering(9)		
Common units issued in the merger		
Total distributions on common units		
Excess (shortfall)(9)		

(1) Includes revenues from our mineral and royalty interests and working interests.

(2) The impairment primarily resulted from decreasing commodity prices and changes in the projections based on the recent historical operating characteristics at the field level. For more information, please read the historical financial statements of BSMC included elsewhere in this prospectus.

(3) Includes cash expenses of commitment fees and agency fees and non-cash amortization of debt issuance costs.

(4) For more information, please read "Summary—Summary Historical and Pro Forma Financial and Data—Non-GAAP Financial Measures."

(5) Represents compensation expense that is settled in common units and would not reduce the amount of cash available to common units.

(6) Reflects incremental general and administrative expenses that we expect to incur as a result of operating as a publicly traded partnership that are not reflected in our pro forma financial statements.

(7) Represents capital expenditures for acquisitions, working interests, and other corporate expenditures. Capital expenditures incurred for acquisitions were $121.6 million and $69.8 million for the year ended December 31, 2013 and for the twelve months ended June 30, 2014, respectively.

(8) Reflects dividends paid on our preferred units. The preferred coupon is 10% on a nominal amount of preferred units outstanding of $157.4 million for the year ended December 31, 2013. As of January 1, 2014, the nominal amount of preferred units outstanding was $157.2 million. Preferred units may be converted at the conversion rate of 907.3629601 common units per preferred unit at any time prior to the consummation of this offering and at the conversion rate of common units per preferred unit at any time subsequent to the consummation of this offering and are mandatorily convertible in annual tranches of 25% beginning January 1, 2015.

(9) Assuming the underwriters' option to purchase additional common units to cover over-allotments is exercised in full and all of our preferred units converted into common units as of the year ended December 31, 2013 and common units as of June 30, 2014, the excess (shortfall) for the year ended December 31, 2013 and for the twelve months ended June 30, 2014 would have (decreased) increased to $ and $, respectively.

Estimated Cash Available for Distribution for the Year Ending December 31, 2015

During the year ending December 31, 2015, we estimate that we will generate $ million of cash available for distribution. In "—Assumptions and Considerations" below, we discuss the major assumptions underlying this estimate. The available cash discussed in the forecast should not be viewed as management's projection of the actual available cash that we will generate during the year ending December 31, 2015. We can give you no assurance that our assumptions will be realized or that we will generate any available cash, in which event we will not be able to pay quarterly cash distributions on our common units.

When considering our ability to generate available cash and how we calculate forecasted available cash, please keep in mind all of the risk factors and other cautionary statements under the headings "Risk Factors" and "Forward-Looking Statements," which discuss factors that could cause our results of operations and available cash to vary significantly from our estimates.

Management has prepared the prospective financial information set forth in the table below to present our expectations regarding our ability to generate $ million of available cash for the year ending December 31, 2015. The accompanying prospective financial information was not prepared with a view toward public disclosure or complying with the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the expected course of action and our expected future financial performance. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on this prospective financial information. Inclusion of the prospective financial information in this prospectus should not be regarded as a representation by any person that the results contained in the prospective financial information will be achieved.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the financial forecast or to update this financial forecast to reflect events or circumstances after the date of this prospectus. In light of the above, the statement that we believe that we will have sufficient available cash to allow us to pay the forecasted quarterly distributions on all of our outstanding common units for the year ending December 31, 2015 should not be regarded as a representation by us or the underwriters or any other person that we will make such distributions. Therefore, you are cautioned not to place undue reliance on this information.

Table of Contents

Neither our independent registered public accounting firm nor any other independent registered public accounting firm has compiled, examined or performed any procedures with respect to the forecasted financial information contained herein, nor has it expressed any opinion or given any other form of assurance on this information or its achievability, and it assumes no responsibility for this forecasted financial information. Our independent registered public accounting firm's reports included elsewhere in this prospectus relate to our audited historical financial statements. These reports do not extend to the table and the related forecasted information set forth below and should not be read to do so.

	Year Ending December 31, 2015
	(in thousands, except per unit data)
Revenues:	
Oil and condensate sales(1)	
Natural gas and natural gas liquids sales	
Gain (loss) on commodity derivative instruments	
Lease bonus and other income	
Total revenues	
Operating expenses:	
Lease operating expense and other	
Production and ad valorem taxes	
Depreciation, depletion and amortization	
Impairment of oil and natural gas properties	
General and administrative expense	
Accretion of asset retirement obligations	
Total operating expenses	
Income from operations	
Other income (expense):	
Interest and investment income	
Interest expense	
Other income	
Total other income (expense)	
Net income	
Adjustments to reconcile to Adjusted EBITDA:	
Add:	
Depletion, depreciation and amortization	
Impairment of oil and natural gas properties	
Accretion of asset retirement obligations	
Interest expense	
EBITDA(1)	
Add:	
Unrealized loss on commodity derivative instruments	
Equity-based compensation expense(2)	
Less:	
Unrealized gain on commodity derivative instruments	
Adjusted EBITDA(1)	
Adjustments to reconcile to estimated cash available for distribution:	
Add:	
Net proceeds from this offering to fund future capital expenditures	
Less:	
Incremental general and administrative expense	
Cash interest expense	
Capital expenditures	
Estimated cash available for distribution	
Less:	
Cash paid to noncontrolling interests	
Preferred unit dividends(3)	
Estimated cash available for distribution on common units	
Estimated cash distribution per common unit	
Estimated aggregate distributions of cash available for distribution to:	
Common units issued in this offering(4)	
Common units issued in the merger	
Total distributions on common units	
Excess(4)	

(1) For more information, please read “Summary—Summary Historical and Pro Forma Financial Data—Non-GAAP Financial Measures.”
(2) Represents compensation expense that is settled in common units and would not impact cash available for distribution.
(3) Reflects dividends paid on our preferred units. The preferred coupon is 10% on a nominal amount of preferred units outstanding of $157.4 million for the year ended December 31, 2013. As of January 1, 2014, the nominal amount of preferred units outstanding was $157.2 million. Preferred units may be converted at the conversion rate of 907.3629601 common units per preferred unit at any time prior to the consummation of this offering and at the conversion rate of common units per preferred unit at any time subsequent to the consummation of this offering and are mandatorily convertible in annual tranches of 25% beginning January 1, 2015. We assume that 75% of the preferred units are outstanding during 2015, which if converted would equal common units.
(4) Assuming the underwriters’ option to purchase additional common units to cover over-allotments is exercised in full and all of our preferred units converted into common units as of January 1, 2015, the excess for the year ending December 31, 2015 would have decreased to $. In addition, assuming the underwriters’ option to purchase additional common units to cover over-allotments is not exercised in full and all of our preferred units converted into common units as of January 1, 2015, the excess for the year ending December 31, 2015 would have decreased to $.

Assumptions and Considerations

Based upon the specific assumptions outlined below and based on the cash distribution policy we expect our board of directors to adopt, we expect to generate cash available for distribution in an amount sufficient to allow us to pay $ per common unit on all of our outstanding common units for the year ending December 31, 2015.

While we believe that these assumptions are reasonable in light of our management’s current expectations concerning future events, the estimates underlying these assumptions are inherently uncertain and are subject to significant business, economic, regulatory, environmental, and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate. If our assumptions are not correct, the amount of actual cash available to pay distributions could be substantially less than the amount we currently estimate and could, therefore, be insufficient to allow us to pay the forecasted cash distribution, or any amount, on our outstanding common units, in which event the market price of our common units may decline substantially. When reading this section, you should keep in mind the risk factors and other cautionary statements under the headings “Risk Factors” and “Forward-Looking Statements.” Any of the risks discussed in this prospectus could cause our actual results to vary significantly from our estimates.

Revenues

We own a diversified portfolio of interests in oil and natural gas properties. Substantially all of our revenues are a function of oil and natural gas production volumes sold and average prices received for those volumes.

Our forecasted 2015 production is derived from both our existing wells from our reserve report and from new wells projected to begin producing during the year. For oil and natural gas wells not currently producing, we utilize information from our operators regarding their drilling plans when available. Such information assists us in estimating both mineral-and-royalty-interest production as well as production from working interest wells in which we expect to participate. In addition, we estimate incremental production based on our historical reserve replacement taking into account play-specific trends, rig counts, and other industry information that we believe may be relevant to our forecast.

The following table sets forth information regarding production associated with our mineral and royalty interests and non-operated working interests on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014 and on a forecasted basis for the year ending December 31, 2015:

	Year Ended December 31, 2013	Twelve Months Ended June 30, 2014	Year Ending December 31, 2015
Aggregate production:			
Oil and condensate (MBbls)	2,626	2,716	
Natural gas (MMcf)	45,400	42,633	
Combined volumes (MBoe)	10,193	9,822	
Average daily production (MBoe/d)	27.9	26.9	
Percentage attributable to mineral and royalty interests:			
Oil and condensate	74%	74%	
Natural gas	63%	66%	

The following table illustrates the relationship between average oil and natural gas realized sales prices and the average WTI and Henry Hub natural gas prices on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014 and on a forecasted basis for the year ending December 31, 2015:

	Year Ended December 31, 2013	Twelve Months Ended June 30, 2014	Year Ending December 31, 2015
Average benchmark prices(1):			
WTI oil price ($/Bbl)	$ 97.98	$ 101.36	
Henry Hub natural gas price ($/Mcf)	$ 3.73	$ 4.29	
Realized prices(2):			
Realized oil and condensate price ($/Bbl)	$ 96.25	$ 95.24	
Realized natural gas price ($/Mcf)(3)	4.07	4.70	

(1) For historical periods, average prices were calculated using daily spot prices provided by the EIA. For the year ending December 31, 2015, the NYMEX average price curve as of , 2014 was used.

(2) Excluding cash settlement on commodity derivative instruments.

(3) Due to the data provided to us as a mineral-and-royalty-interest owner by our operators, we are unable to reliably determine the total volumes associated with NGLs from the production of natural gas on our acreage. As such, the realized prices we receive for natural gas include sales attributable to NGLs.

Any differences between realized prices and NYMEX prices are referred to as differentials. Our realized prices are a function of both quality and location differentials. In estimating our realized prices for the year ending December 31, 2015, we have considered the oil and natural gas NYMEX price curves, our historical realized prices across our asset base, and any forecasted changes in quality or location differentials.

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. We estimate our oil and natural gas revenue resulting from our mineral and royalty interests for the year ending December 31, 2015 will be $ million, compared to $314.2 million and $333.2 million on a pro forma basis for the year ended December 31, 2013 and for the twelve months ended June 30, 2014, respectively. We estimate our oil and natural gas revenue resulting from our non-operated working interests for the year ending December 31, 2015 will be $ million compared to $123.4 million and $125.7 million on a pro forma basis for the year ended December 31, 2013 and for the twelve months ended June 30, 2014, respectively.

We anticipate growth in our mineral-and-royalty-interest revenues due to increased production from our acreage in the Eagle Ford and Bakken Shales and our geographically diverse mineral-and-royalty-interest acreage. We anticipate growth in our working interest revenues due to increased production from our acreage in the Bakken and Haynesville Shales. For information on the effect of changes in prices and productions volumes, please read "—Sensitivity Analysis."

Lease Bonus and Other Income. We also generate revenue through receipt of lease bonus. When we lease our mineral interests, we generally receive an upfront cash payment, or a lease bonus. Lease bonus and other income are estimated to be $ million for the year ending December 31, 2015. Approximately 82% of our acreage is unleased, and we believe this acreage, along with renewals of leased acreage, will provide future bonuses in line with historical averages. Lease bonus and other income on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014 were $31.8 million and $44.1 million, respectively.

Operating Expenses

Of our operating expenses, lease operating expense and other and accretion of asset retirement obligations are attributable solely to our non-operated working interests. Production and ad valorem taxes, depletion, depreciation, and amortization and impairment expense are attributable to both our mineral and royalty interests and our non-operated working interests.

Lease Operating Expenses and Other. Lease operating expenses include normally recurring expenses necessary to operate and produce hydrocarbons from our non-operated working interests in oil and natural gas wells, non-recurring well workovers, repair-related expenses, and exploration expenses. We estimate that lease operating expenses and other for the year ending December 31, 2015 will be $ million as compared to $21.3 million and $20.6 million on a pro forma basis for each of the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively.

Production and Ad Valorem Taxes. Production, or severance, taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the states' regulations 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. We estimate that production and ad valorem taxes for the year ending December 31, 2015 will be $ million, compared to $42.8 million and $44.9 million on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively.

Depletion, Depreciation, and Amortization. Depletion is the amount of cost basis of oil and natural gas properties at the beginning of a period attributable to the volume of hydrocarbons extracted during such period, calculated on a unit-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We have historically adjusted our depletion rates in the fourth quarter of each year based upon the year-end reserve report and other times during the year when circumstances indicate that there has been a significant change in reserves or costs. We estimate that our depletion, depreciation, and amortization for the year ending December 31, 2015 will be $ million, compared to $102.4 million and $98.3 million on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively.

Impairment of Oil and Natural Gas Properties. Individual categories of oil and natural gas properties are assessed periodically to determine if the recorded value has been impaired. Management periodically conducts an in-depth evaluation of the cost of property acquisitions, successful exploratory wells, development activities, unproved leasehold, and mineral interests to identify impairments. We anticipate no impairment expense for the year ending December 31, 2015 as compared to $57.1 million and $29.5 million on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively.

General and Administrative Expense. We estimate that our general and administrative expenses for the year ending December 31, 2015 will be $ million, compared to $59.5 million and $60.5 million on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively. General and administrative expenses for the year ending December 31, 2015 include $ million of compensation expense incurred in connection with our long-term incentive plan, $ million of general and administrative expenses we expect to incur as a result of becoming a publicly traded partnership, $ million of , $ million of and $ million of other general and administrative expenses. Please read “Executive Compensation and Other Information.”

Accretion of Asset Retirement Obligations. An ARO represents an obligation to perform site reclamation, to dismantle production or processing facilities, or to plug and abandon wells. To determine the current amount of ARO, the estimated future cost to satisfy the abandonment obligation, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, is discounted back to the date that the abandonment obligation was incurred. After recording this cost, an ARO is accreted to its future estimated value in order to match the timing of expenses with the periods in which they occurred. We estimate that our accretion expense for the year ending December 31, 2015 will be $ million, compared to $0.6 million and $0.6 million on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively.

Interest Expense. We estimate that interest expense will be $ million for the year ending December 31, 2015 as compared to $3.6 million and $3.6 million on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively. We do not expect to have borrowings outstanding under our credit facility during the year ending December 31, 2015 and only expect to incur commitment and agency expense or related costs during the forecast period. In connection with amending and restating our credit facility in connection with this offering, we expect to incur costs of $ million for the year ending December 31, 2015. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facility.”

Commodity Derivative Contracts

Our ongoing operations expose us to changes in the market price for oil and natural gas. To mitigate the given commodity price risk associated with its operations, we use derivative instruments. From time to time, such instruments may include fixed price contracts, variable to fixed price swaps, costless collars, and other contractual arrangements. However, we currently utilize only costless collars. We do not enter into derivative instruments for speculative purposes. In addition, we employ a “rolling hedge” strategy whereby we do not execute all of our hedges at the same time but instead execute new trades as older hedges settle or expire. The impact of these derivative instruments could affect the amount of revenue we ultimately record.

Our hedge volumes are limited to projected proved developed producing reserve (“PDP”) production as determined by our then most current reserve report. We have traditionally employed a strategy of hedging a high percentage of our aggregate PDP production for the next twelve months with a lesser degree of production hedged for the subsequent twelve-month period. We have historically limited our hedging to a total period of 24 months, with the percentage hedged each month declining over the period. As we only hedge PDP production, our hedges do not account for new wells that are projected to begin producing in the future. Accordingly, our hedged volumes are considerably lower than our actual production for the year. For example, as of January 1, 2013, we had 50.3% of our 2013 PDP production hedged on a Boe basis, which represented 39.1% of our total actual production for the year. Taking into account new hedges executed throughout 2013, the total volumes hedged as a percentage of total annual production for 2013 was 64.0%.

For purposes of the forecast, we have assumed that we do not enter into additional commodity derivative contracts. Our existing hedges will cover MBoe/d, or approximately % of our total forecasted production of MBoe/d for the year ending December 31, 2015. We have assumed that the commodity derivative contracts will consist of zero-cost collars for oil and natural gas. The table below shows the volumes, benchmark price, and prices we have assumed for our commodity derivative contracts for the year ending December 31, 2015:

	Volume	% of Forecasted Production	Weighted-Average Floor Price	Weighted-Average Ceiling Price
Oil and condensate	Bbl	%	$	$
Natural gas	Mcf	%	$	$

Capital Expenditures

We expect to spend approximately $ million on capital expenditures in connection with our non-operated working interests on a forecasted basis for the year ending December 31, 2015, compared to $73.7 million and $61.5 million on a pro forma basis for the year ended December 31, 2013 and the twelve months ended June 30, 2014, respectively.

Although we may make acquisitions during the year ending December 31, 2015, our forecast does not reflect any acquisitions, as we cannot assure you that we will be able to identify attractive properties or, if identified, that we will be able to negotiate acceptable purchase agreements, or if successful, the timing of the closing(s) of any such acquisitions or the commencement of our receipt of revenues therefrom.

Regulatory, Industry, and Economic Factors

Our forecast for the year ending December 31, 2015 is based on the following significant assumptions related to regulatory, industry, and economic factors:

- There will not be any new federal, state, or local regulation of portions of the energy industry in which we operate, or an interpretation of existing regulation, that will be materially adverse to our business;
- There will not be any major adverse change in commodity prices or the energy industry in general;
- Market, insurance, and overall economic conditions will not change substantially; and
- We will not undertake any extraordinary transactions that would materially affect our cash flow.

Forecasted Distributions

We expect that aggregate quarterly distributions of available cash on our common units for the year ending December 31, 2015 will be approximately $ million. While we believe that the assumptions we have used in preparing the estimates set forth above are reasonable based upon management's current expectations concerning future events, they are inherently uncertain and are subject to significant business, economic regulatory, and competitive risks and uncertainties, including those described in "Risk Factors," that could cause actual results to differ materially from those we anticipate. If our assumptions are not realized, the actual available cash that we generate could be substantially less than the amount we currently estimate and could, therefore, be insufficient to permit us to pay any amount of distributions on all our outstanding common units in respect of the four calendar quarters ending December 31, 2015 or thereafter, in which event the market price of the common units may decline materially.

Sensitivity Analysis

Our ability to generate sufficient cash from operations to pay distributions to our common unitholders is a function of two primary variables: (i) production volumes and (ii) commodity prices. In the paragraphs below, we demonstrate the impact that changes in either of these variables, while holding all other variables constant, would have on our ability to generate sufficient cash from our operations to pay quarterly distributions on our common units for the year ending December 31, 2015.

Table of Contents

Production Volume Changes. The following table shows estimated cash available for distribution under production levels of 90%, 100%, and 110% of the production level we have forecasted for the year ending December 31, 2015.

	Percentage of Forecasted Annual Production		
	90%	100%	110%
Forecasted annual production:			
Oil and condensate (Bbls)			
Natural gas (Mcf)			
Combined volumes (Boe)			
Forecasted average daily production:			
Oil and condensate (Bbl/d)			
Natural gas (Mcf/d)			
Combined volumes (Boe/d)			
Forecasted average sales prices:			
WTI oil price ($/Bbl)	$	$	$
Realized oil and condensate sales price ($/Bbl)			
Henry Hub natural gas price ($/Mcf)	$	$	$
Realized natural gas sales price ($/Mcf)			
Estimated cash available for distribution (in thousands):			
Oil and condensate sales			
Natural gas and natural gas liquids sales			
Lease bonus and other income			
Operating expenses			
Estimated cash flow available for distribution			

Commodity Price Changes. The following table shows estimated cash available for distribution under various assumed oil and natural gas prices for the year ending December 31, 2015. The amounts shown below are based on forecasted realized commodity prices that take into account our average NYMEX commodity price differential assumptions. We have assumed no changes in our production based on changes in prices.

	Change in Forecasted Commodity Prices		
	90%	100%	110%
Forecasted annual production:			
Oil and condensate (Bbls)			
Natural gas (Mcf)			
Combined volumes (Boe)			
Forecasted average daily production:			
Oil and condensate (Bbl/d)			
Natural gas (Mcf/d)			
Combined volumes (Boe/d)			
Forecasted average sales prices:			
WTI oil and condensate price ($/Bbl)	$	$	$
Realized oil and condensate sales price ($/Bbl)			
Henry Hub natural gas price ($/Mcf)	$	$	$
Realized natural gas sales price ($/Mcf)			
Estimated cash available for distribution (in thousands):			
Oil and condensate sales			
Natural gas and natural gas liquids sales			
Lease bonus and other income			
Operating expenses			
Estimated cash available for distribution			

SELECTED HISTORICAL AND PRO FORMA FINANCIAL DATA

Black Stone Minerals, L.P. was formed in September 2014 and does not have historical financial statements. Therefore, in this prospectus we present the historical financial statements of BSMC, our predecessor for accounting purposes. We refer to this entity as "Black Stone Minerals, L.P. Predecessor." The following table presents selected historical financial data of BSMC and selected pro forma financial data of Black Stone Minerals, L.P. as of the dates and for the periods indicated.

The selected historical financial data presented as of and for the years ended December 31, 2013 and 2012 are derived from the audited historical financial statements of BSMC that are included elsewhere in this prospectus. The selected historical financial data presented as of and for the six months ended June 30, 2014 and for the six months ended June 30, 2013 are derived from the unaudited historical financial statements of BSMC included elsewhere in this prospectus.

The selected pro forma financial data presented for the year ended December 31, 2013 and as of and for the six months ended June 30, 2014 are derived from our pro forma financial statements included elsewhere in this prospectus. Our pro forma financial statements give pro forma effect to the issuance and sale of the common units from this offering and the application of the net proceeds therefrom as described under "Use of Proceeds." The pro forma balance sheet assumes the events described above occurred as of June 30, 2014. The pro forma statements of operations for the year ended December 31, 2013 and the six months ended June 30, 2014 assume the events described above occurred as of January 1, 2013.

We have not given pro forma effect to incremental general and administrative expenses of approximately $ million that we expect to incur annually as a result of operating as a publicly traded partnership, such as expenses associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NYSE listing, independent-auditor fees, legal fees, investor-relations activities, registrar and transfer agent fees, director-and-officer insurance, and additional compensation.

[Table of Contents](#)

For a detailed discussion of the selected historical financial data contained in the following table, please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” The following table should also be read in conjunction with “Use of Proceeds” and the audited and unaudited historical financial statements of BSMC included elsewhere in this prospectus. Among other things, the historical financial statements include more detailed information regarding the basis of presentation for the information in the following table.

	Black Stone Minerals, L.P. Predecessor Historical				Black Stone Minerals, L.P. Pro Forma	
	Year Ended December 31,		Six Months Ended June 30,		Year Ended December 31,	Six Months Ended June 30,
	2012	2013	2013	2014	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Revenues:						
Oil and condensate sales	$ 202,104	$ 252,742	$ 118,615	$ 124,576	$ 252,742	$ 124,576
Natural gas and natural gas liquids sales	166,849	184,868	95,335	110,640	184,868	110,640
Gain (loss) on commodity derivative instruments	12,275	(5,860)	1,522	(8,343)	(5,860)	(8,343)
Lease bonus and other income	53,918	31,809	7,155	19,476	31,809	19,476
Total revenues	$ 435,146	$ 463,559	$ 222,627	$ 246,349	$ 463,559	$ 246,349
Operating Expenses:						
Lease operating expense and other	$ 20,527	$ 21,316	$ 10,347	$ 9,674	$ 21,316	$ 9,674
Production and ad valorem taxes	36,680	42,813	19,340	21,408	42,813	21,408
Depreciation, depletion and amortization	104,059	102,442	51,090	46,993	102,442	46,993
Impairment of oil and natural gas properties	62,987	57,109	27,630	—	57,109	—
General and administrative expense	50,348	59,501	28,940	29,963	59,501	29,963
Accretion of asset retirement obligations	608	588	307	295	588	295
Total operating expenses	$ 275,209	$ 283,769	$ 137,654	$ 108,333	$ 283,769	$ 108,333
Income from operations	$ 159,937	$ 179,790	$ 84,973	$ 138,016	$ 179,790	$ 138,016
Other income (expense):						
Interest and investment income	$ 209	$ 90	$ 65	$ 24	$ 90	$ 24
Interest expense(1)	(9,166)	(11,342)	(4,747)	(6,852)	(3,633)	(1,835)
Gain on sale of assets	363	18	18	—	18	—
Other income	467	407	137	807	407	807
Total other income (expense)	(8,127)	(10,827)	(4,527)	(6,021)	(3,118)	(1,004)
Net income	$ 151,810	$ 168,963	$ 80,446	$ 131,995	$ 176,672	$ 137,012
Statement of Cash Flow Data:						
Net cash provided by (used in):						
Operating activities	$ 358,002	$ 320,764	$ 142,900	$ 165,860		
Investing activities	(198,975)	(195,631)	(123,855)	(59,855)		
Financing activities	(138,172)	(142,311)	(44,441)	(123,339)		
Other Financial Data:						
EBITDA(2)	$ 328,630	$ 340,444	$ 164,220	$ 186,135	$ 340,444	$ 186,135
Adjusted EBITDA(2)	346,574	354,576	167,942	197,189	354,576	197,189
Capital expenditures(3)	(198,975)	(195,631)	(123,855)	(59,855)		
Balance Sheet Data (at period end):						
Cash and cash equivalents	$ 47,301	$ 30,123		$ 12,789		$
Total assets	1,199,187	1,444,413		1,466,769		
Long-term debt (including current portion)	363,100	451,000		453,000		—
Total liabilities	711,143	566,618		574,744		121,744
Total mezzanine equity	161,381	161,392		161,122		
Total equity	$ 326,663	$ 716,403		$ 730,903		$

(1) Includes cash expenses of commitment fees and agency fees and non-cash amortization of debt issuance costs.
(2) Please read “Summary—Summary Historical and Pro Forma Financial Data—Non-GAAP Financial Measures.”
(3) Net of proceeds from the sale of assets of $1.0 million and $0.1 million for the years ended December 31, 2013 and December 31, 2012, respectively, and $0.1 million for the six months ended June 30, 2013.

Table of Contents

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis of our financial condition and results of operations in conjunction with historical financial statements of our accounting predecessor for financial reporting purposes, BSMC, included elsewhere in this prospectus. 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 "Risk Factors" and "Forward-Looking Statements," and elsewhere in this prospectus.

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 the marketing of our mineral assets for lease, creative structuring of those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working-interest basis. Our primary business objective is to grow our reserves, production, and cash flow while distributing a substantial majority of our cash flow to our common unitholders.

Our mineral and royalty interests consist of mineral interests in approximately 14.5 million acres, with an average 48.2% ownership interest in that acreage, NPRIs in 1.2 million acres, and ORRIs in 1.4 million acres. These non-cost-bearing interests include ownership in approximately 40,000 producing wells. We also own non-operated working interests. We recognize oil and natural gas revenue from our mineral and royalty and non-operated working interests in producing wells when the oil and natural gas production from the associated acreage is sold. Our other sources of revenue include mineral lease bonus, shut-in royalties, and delay rentals, which are recognized as revenue according to the terms of the lease agreements, and management fees from our minority interests and two third parties.

Business Environment

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

Rig Count

Since we do not operate wells, 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 monitor rig counts in an effort to identify existing and future leasing and drilling activity on our acreage.

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

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

	Second Quarter 2014	First Quarter 2014	Fourth Quarter 2013	Third Quarter 2013
Oil	1,558	1,487	1,382	1,362
Natural gas	314	318	374	376
Other	1	4	1	6
Total	1,873	1,809	1,757	1,744

Source: Baker Hughes Incorporated

Natural Gas Storage

The majority 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 year-to-year depending on the demand from the previous winter and the demand for electricity used for cooling during the summer months.

The following table shows natural gas storage volumes by region for each of the quarters presented:

Location	Second Quarter 2014 (Bcf)	First Quarter 2014 (Bcf)	Fourth Quarter 2013 (Bcf)	Third Quarter 2013 (Bcf)
East(1)	923	310	1,501	1,800
West(2)	331	160	412	529
Producing(3)	675	352	1,061	1,158
Total	1,929	822	2,974	3,487

Source: EIA

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

How We Evaluate Our Operations

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

- volumes of oil and natural gas produced;
- commodity prices; and
- EBITDA and Adjusted EBITDA.

Volumes of Oil and Natural Gas Produced

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

Commodity Prices

Factors Affecting the Sales Price of Oil and Natural Gas

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

- *Oil*. The majority of our oil production is sold at prevailing market prices, which fluctuate in response to many factors that are outside of our control. NYMEX Light Sweet Crude (WTI) is the prevailing domestic oil pricing index. The majority of our oil production is priced on this benchmark with the final realized price affected by both quality and location differentials.

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

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

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

  Quality differentials result from the heating value of natural gas measured in Btus and the presence of impurities, such as sulfur, carbon dioxide, and nitrogen. Due to the content of NGLs in high Btu gas, this quality of natural gas nets a higher overall price when compared to low Btu gas. Natural gas with a higher concentration of impurities will receive a lower price due to the cost of treating the natural gas to meet pipeline quality specifications.

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

Hedging

We enter into derivative instruments to partially mitigate the impact of commodity price volatility on our cash flow from operations. From time to time, such instruments may include fixed price contracts, variable to fixed price swaps, costless collars, and other contractual arrangements. However, we currently utilize only costless collars. In addition, we employ a “rolling hedge” strategy whereby we do not execute all of our hedges at the same time but instead execute new trades as older hedges settle or expire. The impact of these derivative instruments could affect the amount of revenue we ultimately record. For further information, please read “— Quantitative and Qualitative Disclosures About Market Risk.”

EBITDA; Adjusted EBITDA

EBITDA and Adjusted EBITDA are non-GAAP supplemental financial measures used by our management and by external users of our financial statements such as investors, commercial banks, research analysts, and others, to assess:

- our ability to make distributions to unitholders;

- the financial performance of our assets without regard to financing methods, capital structure, or historical cost basis;
- the ability of our assets to generate sufficient cash to pay interest costs and support our indebtedness;
- our operating performance and return on capital as compared to those of other companies and partnerships in our industry, without regard to financing or capital structure; and
- the feasibility of acquisitions and other capital expenditures and the overall rates of return on investment opportunities.

We define EBITDA as net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, impairment of oil and natural gas properties, and accretion of AROs. We define Adjusted EBITDA as EBITDA further adjusted for unrealized gains/losses on derivative instruments and non-cash equity-based compensation.

EBITDA and Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income, income from operations, cash flows from operating activities, or any other measure of financial performance or liquidity presented in accordance with GAAP as measures of our operating performance or liquidity. EBITDA and Adjusted EBITDA do not include changes in working capital, capital expenditures, and other items that are set forth in a cash flow statement presentation of our operating, investing, and financing activities. Any measures that exclude these elements have material limitations. Our computation of EBITDA and Adjusted EBITDA may differ from computations of similarly titled measures of other companies.

Factors Affecting the Comparability of Our Financial Results

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

Results of Operations

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Revenues

The following table shows our production, pricing, and revenues for the periods presented (in thousands except for realized prices):

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(unaudited)	
Production:		
Oil and condensate (MBbls)	1,323	1,233
Natural gas (MMcf)	20,228	22,996
Equivalents (Boe)(1)	4,695	5,065
Realized prices:		
Oil and condensate ($/Bbl)	$ 94.15	$ 96.21
Natural gas ($/Mcf)(2)	5.47	4.15
Combined equivalents ($/Boe)	$ 50.10	$ 42.24
Revenues:		
Oil and condensate sales	$124,576	$118,615
Natural gas and natural gas liquids sales	110,640	95,335
Gain (loss) on commodity derivative instruments	(8,343)	1,522
Lease bonus and other income	19,476	7,155
Total revenues	$246,349	$222,627

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

(2) As a mineral-and-royalty-interest owner, we are often provided insufficient and inconsistent data by our operators. As a result, we are unable to reliably determine the total volumes associated with natural gas liquids from the production of natural gas on our acreage. As such, the realized prices we receive for natural gas include sales attributable to natural gas liquids.

Total revenues for the six months ended June 30, 2014 increased $23.7 million, or 10.7%, compared to the six months ended June 30, 2013. The increase was primarily driven by higher realized natural gas prices and higher oil and condensate volumes.

Oil and condensate sales during the period were $6.0 million, or 5.0%, higher than the corresponding period in 2013 primarily due to an increase in production volumes. Our mineral-and-royalty-interest oil volumes accounted for 74.8% and 74.4% of total oil and condensate volumes for the six month period ending June 30, 2014 and the six month period ending June 30, 2013, respectively. The 7.9% increase in mineral-and-royalty-interest oil volumes, period to period, was driven primarily by production increases from new wells in the Eagle Ford Shale. Our working-interest oil volumes increased by 5.6% to 333.5 MBbls during the first half of 2014 versus the first half of 2013 primarily due to new wells in the Bakken/Three Forks play. A 2.1% decrease in realized oil prices partially offset the overall increase in oil and condensate revenue.

Natural gas revenues increased by $15.3 million, or 16.1%, for the six months ended June 30, 2014 as compared to the same period for 2013. A 31.8% increase in the realized natural gas price for the first six months of 2014 versus the same period in 2013 generated the increase. The favorable price variance was partially offset by a decrease in produced volumes. As we expected, natural gas production declined from period to period. The

12.0% decline in both mineral-and-royalty-interest and working-interest volumes was primarily driven by the run-off in production in the Hayneville/Bossier play. In 2008 and 2009, we entered in to lease agreements which covered the majority of our Hayneville/Bossier play acreage in Louisiana and Texas. As operators drilled wells to hold acreage, our natural gas production increased significantly in the play, with the volumes peaking in 2012. With most acreage now held by production, many operators have moved drilling rigs out of the play. Although these wells initially produce at high rates, they tend to decline rapidly, so without consistent drilling activity to replace the high decline rates of the individual wells, the overall production rate from the play has declined. While operators have recently begun to increase the drilling activity on our acreage, the production from these new wells has not yet reached the point of offsetting the declines in the existing wells. Mineral-and-royalty-interest production comprised 68.4% and 61.7% of our natural gas volumes for the first half of 2014 and first half of 2013, respectively.

Lease bonus and delay rental revenue increased $12.3 million, or 172.2%, for the six months ended June 30, 2014 as compared to the same period in 2013. This increase primarily resulted from the successful closing of a significant lease in the Canyon Wash and Canyon Lime plays in Potter County, Texas during the first quarter of 2014.

Operating Expenses

Lease Operating Expenses and Other. Lease operating expenses include normally recurring expenses necessary to operate and produce hydrocarbons from our non-operated working interests in oil and natural gas wells, non-recurring well workovers, repair-related expenses, and exploration expenses. Lease operating expenses decreased by $0.7 million, or 6.5%, for the six months ended June 30, 2014 as compared to the same period in 2013 due to lower production in the Haynesville Shale.

Production and Ad Valorem Taxes. Production, or severance, taxes include statutory amounts deducted from our production revenues by various state taxing entities. Depending on the states' regulations 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 six months ended June 30, 2014, production and ad valorem taxes increased by $2.1 million, or 10.7%, over the six months ended June 30, 2013, generally as a result of higher oil and natural gas sales.

Depreciation, Depletion, and Amortization Expense. Depletion is the amount of cost basis of oil and natural gas properties at the beginning of a period attributable to the volume of hydrocarbons extracted during such period, calculated on a unit-of-production basis. Estimates of proved developed producing reserves are a major component of the calculation of depletion. We have historically adjusted our depletion rates in the fourth quarter of each year based upon the year-end reserve report and other times during the year when circumstances indicate that there has been a significant change in reserves or costs. Depreciation, depletion, and amortization declined $4.1 million, or 8.0%, primarily due to slightly lower natural gas production volumes during the first six months ended June 30, 2014.

Impairment of Oil and Natural Gas Properties. Individual categories of oil and natural gas properties are assessed periodically to determine if the recorded value has been impaired. Management periodically conducts an in-depth evaluation of the cost of property acquisitions, successful exploratory wells, development activities, unproved leasehold, and mineral interests to identify impairments. Impairments totaled $27.6 million for the six months ended June 30, 2013 primarily due to the impact that changes in price had on the value of our reserve estimates. The primary areas negatively impacted by impairments were the Appalachian Basin and the Haynesville/Bossier and Barnett Shale plays. No impairments were recorded during the six months ended June 30, 2014.

General and Administrative Expense. During the six months ended June 30, 2014, general and administrative expenses increased by $1.0 million, or 3.5% as compared to the same time period in 2013. The increase was due to higher costs associated with our long-term incentive plans. Excluding costs associated with our long-term incentive plans, our general and administrative expense has generally tended to remain consistent between periods.

Accretion of Asset Retirement Obligations. An ARO represents an obligation to perform site reclamation, to dismantle production or processing facilities, or to plug and abandon wells. To determine the current amount of ARO, the estimated future cost to satisfy the abandonment obligation, using current prices that are escalated by an assumed inflation factor up to the estimated settlement date, is discounted back to the date that the abandonment obligation was incurred. After recording this cost, an ARO is accreted to its future estimated value in order to match the timing of expenses with the periods in which they occurred. Accretion expense did not vary significantly between the six months ended June 30, 2014 and the six months ended June 30, 2013.

Interest Expense. Interest expense increased by $2.1 million, or 44.3%, due to additional borrowings under our credit facility. Outstanding borrowings during 2014 were higher than 2013, primarily due to increased expenditures for acquisitions, drilling activity, and funding of common equity repurchases during 2013.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Revenues

The following table shows our production, pricing, and revenues for the periods presented (in thousands except for realized prices):

	Year Ended December 31,	
	2013	2012
Production:		
Oil and condensate (MBbls)	2,626	2,173
Natural gas (MMcf)	45,400	52,965
Equivalents (MBoe)(1)	10,193	11,001
Realized Prices:		
Oil and condensate ($/Bbl)	$ 96.25	$ 93.00
Natural gas ($/Mcf)(2)	4.07	3.15
Combined equivalents ($/Boe)	$ 42.93	$ 33.54
Revenues:		
Oil and condensate sales	$252,742	$202,104
Natural gas and natural gas liquids sales	184,868	166,849
Gain (loss) on commodity derivative instruments	(5,860)	12,275
Lease bonus and other income	31,809	53,918
Total revenues	$463,559	$435,146

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

(2) As a mineral-and-royalty-interest owner, we are often provided insufficient and inconsistent data by our operators. As a result, we are unable to reliably determine the total volumes associated with natural gas liquids from the production of natural gas on our acreage. As such, the realized prices we receive for natural gas include sales attributable to natural gas liquids.

Total revenues for the year ended December 31, 2013 increased $28.4 million, or 6.5%, compared to 2012. Revenues from oil production were $50.6 million, or 25.1%, higher than 2012 primarily due to an increase in volumes stemming from the drilling of new wells in the Bakken/Three Forks play, where we own both mineral and royalty interests and working interests, and the Eagle Ford Shale, where we own only mineral and royalty interests. Higher oil prices also contributed to the overall increase in oil and condensate sales. Natural gas and natural gas liquids sales increased by $18.0 million, or 10.8%, year-over-year which was the result of a 29.2% increase in realized natural gas prices (exclusive of any hedging activity). The increase in prices was partially offset by a 14.3% decrease in natural gas production. The decrease in mineral-and-royalty-interest and working-interest natural gas volumes primarily relates to the run-off in production in the Hayneville/Bossier play where reservoir characteristics result in high production decline rates

Lease bonus and delay rental revenue decreased $22.1 million, or 41.0%, for the year ended December 31, 2013 as compared to 2012. During 2013, leasing activity was strong in, among other places, the Austin Chalk, Woodbine, Granite Wash, and Eaglebine plays, all located in Texas. However, 2012 leasing revenue significantly exceeded expectations due to the successful consummation of several large leases in the Brown Dense play and the Tuscaloosa Marine Shale in Mississippi, the Haynesville/Bossier play in Louisiana, and the Woodbine play in Texas.

Operating Expenses

Lease Operating Expenses and Other. Lease operating expenses increased by $0.8 million, or 3.8%, for the year ended December 31, 2013, as compared to the same period in 2012. Our production mix changed from 2012 to 2013 to include higher volumes from oil wells. Lease operating expenses associated with wells which primarily produce oil are typically higher than similar expenses incurred to produce volumes from wells which primarily produce natural gas.

Production and Ad Valorem Taxes. For the year ended December 31, 2013, production and ad valorem taxes increased $6.1 million, or 16.7%, over 2012, as a result of the correlation to higher oil and natural gas sales.

Depreciation, Depletion, and Amortization Expense. DD&A decreased $1.6 million, or 1.6%, for the year ended December 31, 2013 as compared to 2012.

Impairment of Oil and Natural Gas Properties. Impairments totaled $57.1 million for the year ended December 31, 2013, primarily due to the impact changes in prices had on the value of our reserve estimates. The primary areas impacted by impairments were in the Appalachian Basin, the Haynesville/Bossier play, and the Barnett Shale play. Impairments totaled $63.0 million for the year ended December 31, 2012, principally related to properties located in the Appalachian Basin, the Barnett Shale play, and various fields in the Anadarko Basin.

General and Administrative Expense. General and administrative expenses increased $9.2 million, or 18.2%, in 2013 as compared to 2012 primarily as a result of higher costs associated with our long-term incentive plans, contractor costs resulting from land and title work and recording fees associated with assets acquired through the exchange offer. See the notes to our historical financial statements included elsewhere in this prospectus for additional information regarding the exchange offer.

Accretion of Asset Retirement Obligations. Accretion expense did not vary significantly between the year ended December 31, 2013 as compared to 2012.

Interest Expense. Interest expense increased $2.2 million, or 23.7%, due to additional borrowings under our credit facility. Borrowings during the year were higher than 2012 primarily as a result of increased expenditures for acquisitions and repurchases of our common equity.

Liquidity and Capital Resources

Overview

Following the completion of this offering, we expect our primary sources of liquidity to be the net proceeds retained from this offering, cash flows from operations, borrowings under our credit facility, and proceeds from the issuance of equity and debt. We expect our primary uses of cash will be for distributions to our common unitholders and for capital expenditures, including the acquisition of mineral and royalty and working interests and the development of our oil and natural gas properties.

In connection with the closing of this offering, the board of directors of our general partner will adopt a policy pursuant to which we will distribute a substantial majority of the available cash we generate each quarter. Available cash for each quarter will be determined by the board of directors of our general partner following the end of that quarter. Our initial distribution will be $ per common unit on an annualized basis, which we forecast to represent approximately % of our available cash for the year ending December 31, 2015. We may borrow to make distributions to our unitholders when, for example, we believe that the distribution level is sustainable over the long-term, but short-term factors may cause available cash from operations to be insufficient to pay the distribution at the then-current level. The board of directors of our general partner may change the foregoing distribution policy at any time and from time to time. Our partnership agreement does not require us to pay cash distributions on a quarterly or other basis.

It is our intent, for at least the next several years, to finance most of our acquisitions and working-interest capital needs with the retained net proceeds from this offering and borrowings from our credit facility and, in certain circumstances, proceeds from future equity and debt issuances. Replacement capital expenditures are expenditures necessary to replace our existing oil and natural gas reserves or otherwise maintain our asset base over the long-term. Unlike a number of other master limited partnerships, we do not expect to initially retain cash from our operations for replacement capital expenditures, primarily due to our expectation that the development of existing plays and the discovery of new reserves will lead to increasing revenues for at least the next several years. We intend also to add reserves through acquisitions of mineral and royalty interests and through non-operated working-interest participation. We may restrict distributions to our common unitholders, in whole or in part, to fund acquisitions and participation in working interests.

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

Cash Flows

The following table shows our cash flows for the periods presented (in thousands):

	Year Ended December 31,		Six Months Ended June 30,	
	2013	2012	2014	2013
			(unaudited)	
Cash flows from operating activities	$ 320,764	$ 358,002	$ 165,860	$ 142,900
Cash flows used in investing activities	$(195,631)	$(198,975)	$ (59,855)	$(123,855)
Cash flows used in financing activities	$(142,311)	$(138,172)	$(123,339)	$ (44,441)

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Operating Activities. Our operating cash flow is dependent in large part on our production, realized commodity prices, leasing revenues, and operating expenses. For the six months ended June 30, 2014, cash flows from operating activities increased by $23.0 million as compared to the same period in 2013 due to increased realized commodity prices and higher oil and condensate volumes.

Investing Activities. The net cash used in investing activities decreased by $64.0 million in the first six months of 2014 as compared to the same period in 2013 primarily due to reduced capital spent on acquisitions and lower capital expenditures under our working-interest participation program. For the six months ended June 30, 2014, our cash expenditures for acquisitions totaled $29.4 million versus $81.2 million for the same period in 2013. Expenditures for our working interests increased by $12.2 million to $42.4 million for the first half of 2014 versus the first six months of 2013.

Financing Activities. For the first half of 2014, the net cash used by financing activities increased $78.9 million compared to the same period in 2013. During the first six months of 2013, we received $191.6 million in equity contributions as a result of our exchange offer. These contributions were offset by common equity repurchases of $50.2 million, repayments under our credit facility of $46.1 million, and purchases of noncontrolling interests of $24.1 million. Please read the notes to our historical financial statements included elsewhere in this prospectus for additional information regarding the exchange offer.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Operating Activities. Cash flows from operating activities decreased by $37.2 million for 2013 as compared to 2012 primarily due to the fact that lease bonus revenue was $22.1 million lower in 2013; certain leasing arrangements were being negotiated during the latter part of 2013, but the actual execution of such documents was delayed until 2014. In addition, cash flow from operating activities was positively impacted in 2012 by $7.9 million as result of a prepaid royalty that was received in 2012 but was deferred and did not impact the statement of operations until 2013.

Investing Activities. The net cash used in investing activities was essentially unchanged for the year ended December 31, 2013 as compared to the same period in 2012. For 2013, total cash expenditures for acquisitions increased by $11.2 million to $121.6 million but were offset by a $15.6 million reduction of capital spent on our working interests. The reduction in drilling capital was attributable to a decline in expenditures for the Haynesville/Bossier play and a delay until 2014 in the drilling of wells in the Bakken/Three Forks play.

Financing Activities. In 2013, net cash used by financing activities was $4.1 million higher than 2012.

Capital Expenditures

During the first six months of 2014, we spent approximately $29.4 million on three acquisitions. Our 2014 capital forecast for drilling and completion is approximately $85.4 million. Approximately 45% and 25% of our drilling capital budget will be spent in the Bakken/Three Forks play and the Haynesville/Bossier play, respectively, with the remainder spent in various plays including the Granite Wash.

However, the amount and timing of these 2014 capital expenditures is largely discretionary and within our control. We could choose to defer a portion of these planned 2014 capital expenditures depending on a variety of factors, including the success of drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs, and the level of participation by other working-interest owners.

Credit Facility

As of June 28, 2013, we amended and restated our $1.0 billion amended and restated senior secured revolving credit agreement. Under this second amended and restated credit facility, the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base (which is determined based on the value of our oil and natural gas properties). As of June 30, 2014, the borrowing base was $700.0 million, and we had outstanding borrowings of $453.0 million.

In connection with the closing of this offering, we intend to amend and restate our second amended and restated senior secured revolving credit agreement. We expect that the third amended and restated credit facility will have an initial term of years and up to $ billion of borrowing capacity and that the commitment of the lenders equals the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base (which would be determined based on the value of our oil and natural gas properties). Borrowings under the third amended and restated credit facility would be used for the acquisition of properties, cash distributions and other general business purposes.

We expect that outstanding borrowings under the third amended and restated credit agreement will bear interest at a floating rate elected by us equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 1-month LIBOR plus 1.5%) or LIBOR, in each case plus the applicable margin. The applicable margin would range from 0.75% to 1.75% in the case of the alternative base rate and from 1.75% to 2.75% in the case of LIBOR, in each case depending on the amount of borrowings outstanding in relation to the borrowing base. We expect to be obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the borrowings outstanding in relation to the borrowing base. Principal would be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage) and would be 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) and (b) at the maturity date. The facility would be secured by liens on substantially all of our properties.

We expect that the third amended and restated credit agreement will contain various affirmative, negative, and financial maintenance covenants. These covenants, among other things, will limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements, and require the maintenance of certain financial ratios. We expect that the lenders may 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 that the third amended and restated credit agreement will contain customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy, and change of control. There would be 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 expected to be subject to customary cure periods.

Contractual Obligations

The following table summarizes our minimum payments as of December 31, 2013 (in thousands):

		Payments due by period			
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt	$451,000	$ —	$ —	$451,000	$ —
Operating lease obligations	3,961	1,294	2,667	—	—
Total	$454,961	$ 1,294	$2,667	$451,000	$ —

Off-Balance Sheet Arrangements

At December 31, 2013, we did not have any material off-balance sheet arrangements.

Critical Accounting Policies and Related Estimates

The discussion and analysis of our financial condition and results of operations are based upon our historical financial statements, which have been prepared in accordance with GAAP. Certain of our accounting policies involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. The following discussions of critical accounting estimates, including any related discussion of contingencies, address all important accounting areas where the nature of accounting estimates or assumptions could be material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change. Below, we have provided expanded discussion of our more significant accounting estimates.

Please read the notes to our historical financial statements included elsewhere in this prospectus for additional information regarding our accounting policies.

Successful Efforts Method of Accounting

We use the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire interests in oil and natural gas properties are capitalized. The cost of property acquisitions, successful exploratory wells, development costs and support equipment and facilities are initially capitalized when incurred. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are charged to expense when incurred. Mineral and royalty interests and working interests are recorded at cost at the time of acquisition. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

The costs of unproved leaseholds and mineral interests are capitalized as unproved properties pending the results of exploration efforts. As unproved leaseholds are determined to be producing, the related costs are transferred to producing properties. The remaining net book values associated with unproved leaseholds that have expired are charged to exploration expense. Non-producing property costs are assessed periodically, on a property-by-property basis, and a loss is recognized to the extent, if any, the recorded value has been impaired. Any impairment will generally be based on geographic or geologic data.

Mineral interests are recorded at cost at the time of acquisition. Mineral interests are assessed for impairment annually via comparison to third-party valuation information and a loss is recognized to the extent fair value is below the recorded value.

We evaluate impairment of producing properties in accordance with Accounting Standards Codification ("ASC") 360 *Property, Plant, and Equipment*. This standard requires that long-lived assets that are held and used by an entity be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. We estimate the future cash flows expected in connection with the properties and compare such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. When the carrying amount of a property exceeds its estimated undiscounted future cash flows, the carrying amount is reduced to its fair value. Fair value is calculated as the present value of estimated future cash flows of such properties. The factors used to determine fair value include estimates of proved reserves, future commodity prices, timing of future production, future capital expenditures, and a risk-adjusted discount rate.

Asset Retirement Obligations

Under various contracts, permits and regulations, we have legal obligations to restore the land at the end of operations at certain sites. Estimating the future restoration costs necessary for this accounting calculation is difficult. Most of these restoration obligations are many years, or decades, in the future and the contracts and regulations often have vague descriptions of what practices and criteria must be met when the event actually occurs. Asset restoration technologies and costs, regulatory and other compliance considerations, expenditure timing, and other inputs into valuation of the obligation, including discount and inflation rates, are also subject to change.

Revenue Recognition

We recognize revenue when it is realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the seller's price to the buyer is fixed or determinable, and (iv) collectability is reasonably assured. We recognize oil and natural gas revenue from our interests in producing wells when the associated production is sold. Our other sources of revenue include mineral lease bonus, shut-in royalties, and delay rentals, which are recognized as revenue according to the terms of the lease agreements, and management fees from our minority interests and two third parties, which are recognized in accordance of the terms of the respective management agreements.

Derivatives and Financial Instruments

Our ongoing operations expose us to changes in the market price for oil and natural gas. To mitigate the given commodity price risk associated with its operations, we use derivative instruments. From time to time, such instruments may include fixed price contracts, variable to fixed price swaps, costless collars, and other contractual arrangements. However, we currently utilize only costless collars. We do not enter into derivative instruments for speculative purposes. In addition, we employ a "rolling hedge" strategy whereby we do not execute all of our hedges at the same time but instead execute new trades as older hedges settle or expire. The impact of these derivative instruments could affect the amount of revenue we ultimately record.

In accordance with ASC 815, *Derivatives and Hedging*, derivative instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. If a right of offset exists under master netting arrangements and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the consolidated balance sheet. Gains and losses arising from changes in the fair value of derivatives are recognized on a net basis in the accompanying consolidated statements of operations within gain (loss) on commodity derivative instruments.

Although these derivative instruments may expose us to credit risk, we monitor the creditworthiness of our counterparties.

Equity-based compensation

We recognize equity-based compensation expense for restricted common units awarded to our employees and the board of directors of our general partner. The total compensation expense related to the time-based restricted common units is measured as the number of units granted multiplied by the grant date fair value per unit. Compensation expense is recognized on a straight-line basis over the service period (generally equivalent to the vesting period).

Determination of the fair value of the awards requires judgments and estimates regarding, among other things, the appropriate methodologies to follow in valuing the incentive restricted unit grants and the related inputs required by those valuation methodologies. To determine the fair value of the equity-based awards' unit price, we engage third-party valuation specialists and rely on generally accepted valuation techniques, which include the net asset value method under the asset approach, the guideline public company method under the market approach, and the dividend discount method of the income approach. These methods are dependent upon various assumptions to develop the estimates in our operating results, commodity prices, and market-based discount rates. We also consider publicly available information on comparable public companies and our historical transactions and performance in making these estimates. There is inherent uncertainty in making these estimates as the assumptions require significant judgment and are subject to change as a result of new operating data and economic and other conditions that impact our business.

As of the valuation date of January 1, 2014, we were not planning to pursue an initial public offering. We believe that it is reasonable to expect that the completion of an initial public offering will add value to our restricted common units because they will have increased liquidity and marketability. The following table shows restricted common units granted, in thousands except for per unit amounts, since June 30, 2013:

Grant Date	Number of Units Granted	Fair Value Per Unit at Grant Date	Aggregate Fair Value of Units Granted
January 1, 2014	6,097	$ 1.61	$ 9,816

Future results of operations for any particular quarterly or annual period could be materially affected by changes in our assumptions. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the equity-based compensation expense recognized. Please read Note 11 to the historical financial statements of BSMC included elsewhere in this prospectus for additional information. Equity-based compensation expense related to restricted common unit grants is included in general and administrative expense within the consolidated statements of operations.

New and Revised Financial Accounting Standards

The effects of new accounting pronouncements are discussed in the notes to our historical financial statements included in elsewhere in this prospectus.

Quantitative and Qualitative Disclosure about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of oil and natural gas production by our operators. Realized pricing is primarily driven by the prevailing worldwide price for oil and U.S. spot market prices for natural gas production. Pricing for oil and natural gas production has been unpredictable for several years, and we expect this unpredictability to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, historically we have executed hedge contracts, the majority being costless collars, to reduce our exposure to price risk in the spot market for oil and natural gas. The counterparties to the contracts are unrelated third parties. The contracts settled monthly in cash based on a designated floating price. Historically the designated floating price has been based off the NYMEX index for oil and natural gas. We have not designated any of our contracts as fair value or cash flow hedges. Accordingly, the changes in fair value of the contracts are included in net income in the period of the change.

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. Our counterparties are composed of 11 institutions, 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 customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. However, we believe the credit risk associated with our operators and customers is acceptable.

Interest Rate Risk

We will have exposure to changes in interest rates on our indebtedness. As of June 30, 2014, we had total borrowings outstanding under our credit facility of $453.0 million. The impact of a 1% increase in the interest rate on this amount of debt would have resulted in an increase in interest expense, and a corresponding decrease in our results of operations, of approximately $4.5 million annually, assuming, however, that our indebtedness remained constant throughout the year. We may use certain derivative instruments to hedge our exposure to variable interest rates in the future, but we do not currently have in place any hedges.

BUSINESS

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 the marketing of our mineral assets for lease, creative structuring of those leases to encourage and accelerate drilling activity, and selectively participating alongside our lessees on a working-interest basis. Our primary business objective is to grow our reserves, production, and cash flow while distributing a substantial majority of our cash flow to our common unitholders.

We own mineral interests in approximately 14.5 million acres, with an average 48.2% ownership interest in that acreage. We also own nonparticipating royalty interests in 1.2 million acres and overriding royalty interests in 1.4 million acres. These non-cost-bearing interests, which we refer to collectively as our "mineral and royalty interests," include ownership in approximately 40,000 producing wells. Our mineral and royalty interests are located in 41 states and in 62 onshore basins in the continental United States. Many of these interests are in active resource plays, including the Bakken/Three Forks play, Eagle Ford Shale, Wolfcamp play, Haynesville/Bossier play, Granite Wash play, and Fayetteville Shale, as well as emerging plays such as the Tuscaloosa Marine Shale and the Canyon Lime play. The combination of the breadth of our asset base and the long-lived, non-cost-bearing nature of our mineral and royalty interests exposes us to potential additional production and reserves from new and existing plays without investing additional capital.

Our history dates back to 1876, when W.T. Carter & Bro., a predecessor of BSMC, was established as a lumber company in Southeast Texas. W.T. Carter & Bro. acquired significant land holdings for timber, and those acquisitions typically included mineral interests. Beginning in the late 1960s, we began to divest the timber and surface rights on our properties but retained the mineral interests. We began developing our prospective oil and natural gas acreage in the 1980s. In 1985, we were involved in the discovery of the Double A Wells Field in East Texas, a natural gas field that has produced over 540 Bcfe to date. In 1992, we made our first third-party acquisition of mineral interests and, in 1998, shifted our focus from exploration to acquisitions of mineral and royalty interests. In the aggregate, we have invested approximately $1.6 billion in 42 third-party transactions involving mineral and royalty interests and, to a lesser extent, non-operated working interests. We believe that one of our key strengths is our management's extensive experience in acquiring and managing mineral and royalty interests. Our management team has a long history of creating unitholder value and has developed a scalable business model that has allowed us to integrate significant acquisitions into our existing organizational structure quickly and cost-efficiently. Our average daily production for the six months ended June 30, 2014 was approximately 25.9 MBoe/d, which includes production from our mineral and royalty interests, as well as production attributable to our working-interest participation program.

Our Assets

Mineral and Royalty Interests

Mineral interests are real-property interests that are typically perpetual and grant ownership of the oil and natural gas under a tract of land and the rights to explore for, drill for, and produce oil and natural gas on that land or to lease those exploration and development rights to a third party. When those rights are leased, usually for a three-year term, we typically receive an upfront cash payment, known as lease bonus, and we retain a mineral royalty, which entitles us to a cost-free percentage (usually ranging from 20% to 25%) of production or production revenue. A lessee can extend the lease beyond the initial lease term with continuous drilling, production, or other operating activities. When production or drilling ceases, the lease terminates, allowing us to lease the exploration and development rights to another party. Mineral interests generate the substantial majority of our revenue and are also the assets that we have the most influence over.

In addition to mineral interests, we also own other types of non-cost-bearing royalty interests, which include:

- *nonparticipating royalty interests*, or NPRIs, which are royalty interests that are carved out of the mineral estate and represent the right, which is typically perpetual, to receive a fixed, cost-free percentage of production or revenue from production, without an associated right to lease or receive lease bonus; and
- *overriding royalty interests*, or ORRIs, which are royalty interests that burden working interests and represent the right to receive a fixed, cost-free percentage of production or revenue from production from a lease. ORRIs remain in effect until the associated leases expire.

Our revenue generated from these mineral and royalty interests was $314.2 million and $173.0 million for the year ended December 31, 2013 and the six months ended June 30, 2014, respectively.

Working-Interest Participation Program

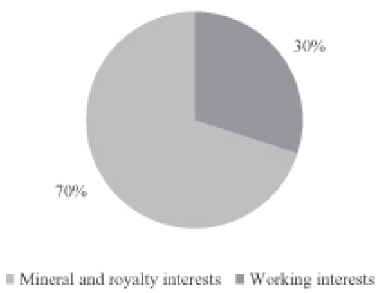
We own working interests related to our mineral interests in various plays across our asset base. Many of these working interests were acquired through working-interest participation rights, which we often include in the terms of our leases. This participation right complements our core mineral-and-royalty-interest business because it allows us to realize additional value from our minerals. Under the terms of the relevant leases, we are granted a unit-by-unit or a well-by-well option to participate on a working-interest basis in drilling opportunities on our mineral acreage. This right to participate in a unit or well is exercisable at our sole discretion. We generally only exercise this option when the results from prior drilling and production activities have substantially reduced the economic risk associated with development drilling, and where we believe the probability of achieving attractive economic returns is high. When we participate, we are required to pay our portion of the costs associated with drilling and operating these wells.

We also own other working interests, unrelated to our mineral and royalty assets, which were acquired because of the attractive working-interest investment opportunities within the assets. The majority of these assets are focused in the Anadarko Basin, and to a lesser extent, in the Permian Basin and Powder River Basin. While these assets have been a successful part of our overall working-interest participation program, they represent approximately 10% of our 2014 non-operated working-interest capital expenditure budget and likely will be less in the future.

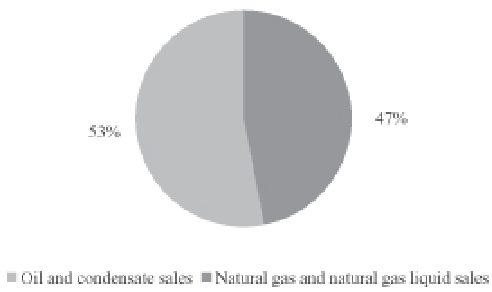
We collectively refer to these working interests as our “working-interest participation program.” When we participate in non-operated working interest opportunities, we are required to pay our portion of the costs associated with drilling and operating these wells. Our 2014 drilling capital expenditure budget associated with our working-interest participation program is $85.4 million, which is being invested primarily in the Bakken/Three Forks, Haynesville/Bossier, and Granite Wash plays. We historically have participated in approximately 200 new wells per year. As of June 30, 2014, we owned non-operated working interests in approximately 7,800 gross wells. For the year ended December 31, 2013 and the six months ended June 30, 2014, our revenue generated from these working interests was $123.4 million and $62.2 million, respectively.

The following graphs provide information regarding our production and revenue for the six months ended June 30, 2014.

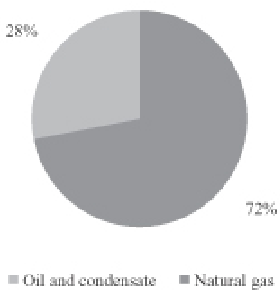
Production by Interest Type



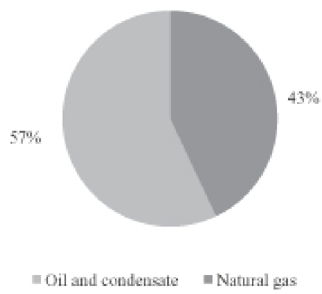
Revenue by Product



Production by Product (Boe 6:1)



Production by Product (Boe 20:1)



Reserves

As of December 31, 2013, our total estimated proved oil and natural gas reserves were 58,942 MBoe based on a reserve report prepared by Pressler, a third-party petroleum engineering firm. Of these reserves, approximately 95.2% were proved developed reserves (approximately 93.5% proved developed producing and 1.7% proved developed non-producing) and approximately 4.9% were proved undeveloped reserves. We generally do not have our operators' approved development plans. As a result, our proved undeveloped reserve estimates are limited to those relatively few locations for which we have received and approved an Authority for Expenditure ("AFE"). At December 31, 2013, our estimated proved reserves were 32.1% oil and 67.9% natural gas.

Business Strategies

Our primary business objective is to grow our reserves, production, and cash flow over the long term, while distributing a substantial majority of our cash flow to our common unitholders. We intend to accomplish this objective by continuing to execute the following strategies:

- ***Actively lease our minerals to third-party operators***. We intend to continue actively marketing our mineral interests for lease in order to generate income from lease bonus and ensure that our acreage is drilled as quickly as possible. Our staff actively manages the leasing of our acreage in order to accelerate royalty revenue and maximize our working-interest optionality. While our leasing activity generates significant revenue from lease bonus, the size and frequency of lease bonus vary depending on the oil and natural gas industry's perception of the prospectivity, risk, and potential economics of a play.

During the lease-negotiation process, we consider standard industry lease terms as well as innovative terms that are designed to encourage more exploration. Through our control of large blocks of contiguous acreage throughout the country, we provide exploration and production companies with an extensive acreage inventory from which to generate prospects and search for new opportunities. In addition, our in-house geological and geophysical team uses our extensive seismic library to assist exploration and production companies in the identification of emerging plays and potential drilling locations. In this prospectus, we define identified potential drilling locations as locations specifically identified by management based on evaluation of applicable geologic and engineering data accrued over our multi-year historical drilling activities. When leasing acreage, we consider the potential lessee's operational track record to ensure that we maximize the pace of development. Our leases often contain provisions which provide us the option to participate on a working-interest (cost-bearing) basis in the operators' third-party drilling programs. Typically, this option is structured to allow us to elect to participate after the operator has demonstrated repeatable attractive economics, thereby allowing us to increase our exposure to a play after the risks of failure or poor returns have been substantially reduced.

- ***Acquire additional mineral and royalty interests in oil and natural gas properties that meet our acquisition criteria.*** We intend to continue to acquire mineral and royalty interests that have substantial resource and cost-free, or organic, growth potential. Our management team has a long history of evaluating, pursuing, and consummating acquisitions of oil and natural gas mineral and royalty interests in the United States. We believe that our large network of industry relationships provides us with a competitive advantage in pursuing potential acquisition opportunities. Since 1992, we have invested approximately $1.6 billion in 42 acquisitions. In the future, we expect to focus on relatively large acquisitions but will also continue to pursue smaller mineral packages to complement an existing position or to establish a foothold in an emerging play. We prefer acquisitions that meet the following criteria:
  - sufficient current production to create near-term accretion for our unitholders;
  - geologic support for future production and reserve growth;
  - a geographic footprint that we believe is complementary to our diverse portfolio and maximizes our potential for upside reserve and production growth from undiscovered reserves or new plays; and
  - targeted positions in high-growth resource and conventional plays.
- ***Participate in drilling opportunities in low-risk plays that generate attractive returns.*** Our ownership of mineral interests affords us the favorable position of negotiating leases that frequently provide us a unit-by-unit or well-by-well option to participate on a working-interest basis in economic, low-risk drilling opportunities. This participation program offers access to drilling opportunities in established producing trends at well-level economics, often unburdened by traditional land and exploration costs associated with acquiring prospective acreage, such as paying lease bonus, acquiring seismic data, and drilling exploratory and delineation wells. We expect to continue to actively participate in these drilling opportunities.
- ***Maintain a conservative capital structure and prudently manage the business for the long term.*** We are committed to maintaining a conservative capital structure that will afford us the financial flexibility to execute our business strategies on an ongoing basis. Upon completion of this offering, we will have no outstanding indebtedness. We believe that proceeds from this offering, internally generated cash flows, our $ million borrowing base under our credit facility, and access to the public capital markets will provide us with sufficient liquidity and financial flexibility to grow our production, reserves, and cash flow through the continued development of our existing assets and accretive acquisitions of mineral and royalty interests.

Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies and achieve our primary business objective:

- ***Significant diversified portfolio of mineral and royalty interests in mature producing basins and exposure to prospective exploration opportunities***. We have a large-scale, diversified asset base with exposure to active high-quality conventional and unconventional plays. With our mineral and royalty interests spanning over 16.5 million total acres across the continental United States, we have established a strong position with significant growth opportunities and exposure to potentially large new discoveries in the future. Several of our positions are in basins still in the early stages of development, including the Bakken Shale, Eagle Ford Shale and Haynesville Shale. In some cases, we have built our positions in anticipation of development in a play, as we did in the Eagle Ford Shale. In other cases, we acquired diversified mineral packages in rich geologic basins with multiple prospective horizons from which subsequent resource plays, including the Bakken/Three Forks play and the Haynesville/Bossier play, have developed. Because our asset base is large and diversified, we are able to make significant focused acquisitions in active areas within well-established resource plays, while maintaining overall diversity. Furthermore, the geographic breadth of our assets and vast quantity of our property interests expose us to potential production and reserves from new and existing plays without further required investment on our behalf. We believe that we will continue to benefit from these cost-free additions of production and reserves for the foreseeable future as a result of technological advances and continuing interest by third-party producers in exploration and development activities on our acreage.
- ***Exposure to many of the leading resource plays in the United States.*** We expect our reserves and cash available for distributions per unit to grow organically for the next several years as our operators continue to drill new wells on the acreage we have leased to them. We believe that we have significant drilling inventory remaining in our interests in multiple resource plays.
- ***Ability to increase exposure in most economic plays through our working-interest participation program.*** We frequently negotiate our leases with options to participate in wells on a working-interest basis. This working-interest option allows us to increase our exposure to plays that we find attractive when the results from prior drilling and production have substantially reduced the economic risk associated with development drilling and where we believe the probability of achieving attractive economic returns is high. We intend to continue increasing our exposure to those opportunities.
- ***Scalable business model.*** We believe that our size, organizational structure, and capacity give us a relative advantage in growing our business because we are able to add large packages of mineral and royalty interests without significantly increasing our cost structure, allowing us to be more competitive when pursuing acquisition opportunities. Our land, accounting, engineering and geology, information-technology, and business-development departments have developed a scalable business model that allows us to manage our existing assets efficiently and absorb significant acquisitions without material cost increases.
- ***Exposure to natural gas supply and demand growth.*** Over the past decade, the combination of horizontal drilling and hydraulic fracturing has provided access to large volumes of shale gas resources that were previously uneconomic to produce. In the United States, the availability of large quantities of shale gas has provided a commodity price advantage over coal and other international natural gas supply options. The EIA projects that U.S. natural gas demand from internal consumption is expected to increase from 25.6 trillion cubic feet in 2012 to 31.6 trillion cubic feet in 2040, driven primarily by increased electricity generation and industrial use. International demand for exports of U.S. natural gas, through pipelines and liquefied natural gas, is forecasted to grow to 5.8 trillion cubic feet per year by 2040. The EIA forecasts the total demand for U.S. natural gas to reach 37.4 trillion cubic feet in 2040. As a result of this increase in demand, the EIA projects U.S. natural gas production to increase from 24.1 trillion cubic feet in 2012 to 37.5 trillion cubic feet in 2040, a 56% increase. Almost all of this increase is due to projected growth in natural gas production from resource plays, which is projected to

grow from 9.7 trillion cubic feet in 2012 to 19.8 trillion cubic feet in 2040. We have significant exposure to domestic natural gas resource plays, including the Haynesville/Bossier play, the Fayetteville Shale, and the Barnett Shale, and we believe that these assets will provide meaningful upside in production and revenue growth as demand for natural gas increases. Our gas assets throughout the U.S. Gulf Coast are well-positioned geographically to take advantage of the growing liquefied natural gas export market.

- ***Financial flexibility to fund expansion.*** Upon the completion of this offering and the application of the net proceeds as set forth under "Use of Proceeds," we expect to have no indebtedness outstanding, approximately $ million of cash on hand, and $ million of undrawn borrowing capacity under our credit facility. The credit facility, combined with internally generated cash flow and access to the public capital markets, will provide us with the financial capacity and flexibility to grow our business.
- ***Experienced and proven management team.*** The members of our executive team have an average of over 25 years of industry experience and have a proven track record of executing accretive acquisitions and maximizing asset development. We expect to benefit from the longstanding relationships fostered by our management team within the industry and the decades-long track record of successful acquisitions of mineral and royalty interests. We believe the experience of our management team in acquiring and managing mineral and royalty interests will allow us to continue to grow our production, reserves, and distributions.

Our Properties

Material Basins and Producing Regions

The following is an overview of the U.S. basins and regions we consider most material to our current and future business.

- ***Louisiana-Mississippi Salt Basins***. The Louisiana-Mississippi Salt Basins region ranges from northern Louisiana and southern Arkansas through south central and southern Mississippi, southern Alabama, and the Florida Panhandle. The Haynesville/Bossier play, which has been extensively delineated through drilling, is the most prospective unconventional play for natural gas production and reserves within this region. Approximately half of the Haynesville/Bossier play's prospective acreage is within the Louisiana-Mississippi Salt Basins region, where we own significant mineral and royalty interests and working interests. The Tuscaloosa Marine Shale play is the basin's most significant emerging unconventional oil play, extending through southwestern Mississippi and southeastern Louisiana on the eastern end of the play and westward across central Louisiana to the Texas border. The play is in the early stage of development and is actively being drilled and tested by several operators. We have a significant mineral-and-royalty-interest position across the entire basin, with material exposure to the Tuscaloosa Marine Shale. There are a number of additional active conventional and unconventional plays in the basin in which we hold considerable mineral and royalty interests, including the Brown Dense, Cotton Valley, Hosston, Norphlet, Smackover, and Wilcox plays.
- ***Western Gulf***. The Western Gulf region, which ranges from South Texas through southeastern Louisiana, includes a variety of both conventional and unconventional plays. We have extensive exposure to the Eagle Ford Shale in South Texas, where we are experiencing a significant level of development drilling on our mineral interests within the oil and rich-gas condensate areas of the play. We also have significant exposure to the Tuscaloosa Marine Shale in central and southeastern Louisiana, which is one of the most prospective emerging oil shale plays in the basin and is being actively drilled and tested by several operators in the Western Gulf region. In addition to the Eagle Ford Shale and Tuscaloosa Marine Shale plays, there are a number of other active conventional and unconventional plays to which we have exposure to in the region, including the Austin Chalk, Buda, Eaglebine (or Maness) Shale, Frio, Glenrose, Olmos, Woodbine, Vicksburg, Wilcox, and Yegua plays.
- ***Williston Basin*.** The Williston Basin stretches through all of North Dakota, the northwest part of South Dakota, and eastern Montana and includes plays such as the Bakken/Three Forks play, where we have

significant exposure through our mineral and royalty interests as well as through our working interests. We are also exposed to other well-known plays in the basin, including the Duperow, Mission Canyon, Madison, Ratcliff, Red River, and Spearfish plays.

- ***Palo Duro Basin*****.** The Palo Duro Basin covers much of the Texas Panhandle but also occupies a small portion of the Oklahoma Panhandle and extends partially into New Mexico to the west. We have a significant acreage position in the Palo Duro Basin, much of which underlies an emerging unconventional oil play in the Canyon Lime. We are also well positioned relative to a number of other active conventional and unconventional plays in the Palo Duro Basin, including the Brown Dolomite, Canyon Wash, Cisco Sand, and Strawn Wash plays.
- ***Permian Basin*****.** The Permian Basin ranges from southeastern New Mexico into West Texas and is currently one of the most active areas for drilling in the United States. It includes three geologic provinces: the Midland Basin to the east, the Delaware Basin to the west, and the Central Basin in between. Our acreage underlies prospective areas for the Wolfcamp play in the Midland and Delaware Basins, the Spraberry formation in the Midland Basin, and the Bone Springs formation in the Delaware Basin, which are among the plays most actively targeted by drillers within the basin. In addition to these plays, we own mineral and royalty interests that are prospective for a number of other active conventional and unconventional plays in the Permian Basin, including the Atoka, Clearfork, Ellenberger, San Andres, Strawn, and Wichita Albany plays.
- ***Anadarko Basin*****.** The Anadarko Basin encompasses the Texas Panhandle, southeastern Colorado, southwestern Kansas, and western Oklahoma. We own mineral and royalty interests as well as working interests in prospective areas for most of the prolific plays in this basin, including the Granite Wash, Atoka, Cleveland, and Woodford Shale plays. Other active plays in which we hold interests in prospective acreage include the Cottage Grove, Hogshooter, Marmaton, Springer, and Tonkawa plays.
- ***Appalachian Basin*****.** The Appalachian Basin covers most of Pennsylvania, eastern Ohio, West Virginia, western Maryland, eastern Kentucky, central Tennessee, western Virginia, northwestern Georgia, and northern Alabama. The basin's most active play in which we have acreage is the Marcellus Shale, which covers most of western Pennsylvania and the northern part of West Virginia. In addition to the Marcellus Shale, there are a number of other active conventional and unconventional plays to which we have material exposure in the Appalachian Basin, including the Berea, Big Injun, Devonian, Huron, Rhinestreet, and Utica plays.
- ***East Texas Basin*****.** The East Texas Basin ranges from central East Texas to northeast Texas and includes the Haynesville/Bossier play and the Cotton Valley play, which are among the most prolific gas plays in the basin. We own a material acreage position in the Shelby Trough area of the Haynesville/Bossier play located in San Augustine and Nacogdoches Counties, which is one of the most active areas being drilled today for that play in the East Texas Basin. There are other active plays to which we have significant exposure, including the Bossier Sand, Goodland Lime, James Lime, Pettit, Travis Peak, Smackover, and Woodbine plays.
- ***Arkoma Basin***. The Arkoma Basin stretches from southeast Oklahoma through central Arkansas. The Fayetteville Shale play is one of the basin's most active unconventional gas plays. We own material mineral and royalty interests within the prospective area of the Fayetteville Shale. In addition, we have interests exposed to a number of other active conventional and unconventional plays in the basin, including the Atoka, Cromwell, Dunn, Hale, and Woodford Shale plays.
- ***Bend Arch-Fort Worth Basin***. The Bend Arch-Fort Worth Basin covers much of north central Texas and includes the Barnett Shale play as its most active unconventional play. Through our mineral and royalty interest in this basin, we have significant exposure to the Barnett Shale as well as a number of other active conventional and unconventional plays in the basin, including the Bend Conglomerate, Caddo, Marble Falls, and Mississippian Lime plays.
- ***Southwestern Wyoming***. The Southwestern Wyoming region covers most of southern and western Wyoming. The Pinedale Anticline is one of the basin's largest producing fields and mainly produces

from the Lance formation. We have a meaningful position in the Pinedale Anticline, and we have interests prospective for other active plays as well, including the Mesaverde, Niobrara, and Wasatch plays.

Interests by USGS Petroleum Province

The following tables present information about our mineral-and-royalty-interest and non-operated working-interest acreage, production, and well count by basin. We may own more than one type of interest in the same tract of land. For example, where we have acquired working interests through our working-interest participation program in a given tract, our working-interest acreage in that tract will relate to the same tract acres as our mineral-interest acreage in that tract. Consequently, some of the acreage shown for one type of interest below may also be included in the acreage shown for another type of interest. Because of our working-interest participation program, overlap between working-interest acreage and mineral and royalty acreage is significant, while overlap between the different types of mineral and royalty interests is not significant.

Mineral Interests

The following table sets forth information about our mineral interests:

				Average Daily Production (Boe/d)			
				6:1(4)(5)		20:1(4)(6)	
USGS Petroleum Province(1)	Acres	Average Ownership Interest(2)	Average Percent Leased(3)	Year Ended December 31, 2013	Six Months Ended June 30, 2014	Year Ended December 31, 2013	Six Months Ended June 30, 2014
Louisiana-Mississippi Salt Basins	5,270,887	54.6%	6.3%	5,442	4,113	2,040	1,612
Western Gulf (onshore)	1,543,217	55.7%	34.3%	3,548	4,057	2,349	2,588
Williston Basin	1,113,210	16.8%	23.3%	1,601	1,934	1,466	1,658
Palo Duro Basin	1,010,374	46.7%	14.0%	15	15	12	12
Permian Basin	678,105	18.2%	36.8%	498	576	408	449
Eastern Great Basin	599,342	96.8%	0.5%	—	—	—	—
Black Warrior Basin	591,842	54.7%	2.6%	41	43	14	15
Anadarko Basin	534,967	33.1%	60.1%	811	806	381	382
Appalachian Basin	490,006	39.6%	31.2%	63	82	22	27
East Texas Basin	406,814	56.3%	55.5%	993	765	323	256
Arkoma Basin	331,168	54.2%	26.3%	1,547	1,759	477	543
Western Great Basin	308,258	88.9%	—	—	—	—	—
Piedmont	179,484	67.8%	—	—	—	—	—
North-Central Montana	151,113	14.7%	17.1%	4	5	2	2
Bend Arch-Fort Worth Basin	138,018	20.6%	31.7%	324	258	119	94
Atlantic Coastal Plain	117,326	12.2%	—	—	—	—	—
Cherokee Platform	106,568	13.8%	29.7%	32	39	20	25
Illinois Basin	79,096	53.7%	5.9%	1	1	1	1
Powder River Basin	66,332	10.9%	15.5%	2	2	2	2
Uinta-Piceance Basin	58,227	3.2%	78.7%	5	4	3	3
Other	695,381	35.2%	14.1%	332	300	154	143
Total	14,469,736	48.2%	17.8%	15,260	14,758	7,793	7,810

Note:Numbers may not add up to total amounts due to rounding.

(1) The basins and regions shown in the table are consistent with USGS petroleum-province delineations.

(2) Ownership interest is equal to the percentage that our undivided ownership interest in a tract bears to the entire tract. The per-basin average ownership interest shown reflects the weighted average of our ownership interests in all tracts in the

basin. Our weighted-average mineral royalty for all of our mineral interests is approximately 20%, which may be multiplied by our ownership interest to approximate the average royalty interest in our mineral and royalty interests.

(3) The average percent leased reflects the weighted average of our leased acres relative to our total acreage on a tract-by-tract basis in the basin.

(4) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each basin for periods in which we have not received sufficient production data from our operators.

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

(6) “Value-equivalent” production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of “oil equivalent,” which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

NPRIs

The following table sets forth information about our NPRIs:

				Average Daily Production (Boe/d)			
				6:1(4)(5)		20:1(4)(6)	
USGS Petroleum Province(1)	**Acres**	**Average Royalty Interest(2)**	**Average Percent Leased(3)**	**Year Ended December 31, 2013**	**Six Months Ended June 30, 2014**	**Year Ended December 31, 2013**	**Six Months Ended June 30, 2014**
Permian Basin	541,434	3.5%	21.4%	3	7	2	5
Western Gulf (onshore)	180,901	5.2%	34.0%	5	23	3	21
North-Central Montana	127,467	3.0%	8.3%	—	—	—	—
Louisiana-Mississippi Salt Basins	111,707	6.8%	24.5%	—	3	—	3
Williston Basin	60,734	2.7%	27.4%	31	56	28	48
Bend Arch-Fort Worth Basin	52,208	4.1%	7.1%	2	3	1	1
East Texas Basin	36,113	3.2%	77.0%	1	—	—	—
Powder River Basin	32,424	6.3%	4.2%	—	—	—	—
Palo Duro Basin	22,791	3.8%	1.7%	—	—	—	—
Anadarko Basin	10,628	4.4%	94.0%	3	1	1	1
Cambridge Arch-Central Kansas Uplift	8,583	5.7%	83.1%	—	—	—	—
Montana Thrust Belt	6,474	3.2%	14.7%	—	—	—	—
Southwest Montana	6,307	5.3%	5.1%	—	—	—	—
Arkoma Basin	5,170	4.5%	71.6%	—	10	—	3
Cherokee Platform	2,634	4.6%	30.4%	—	—	—	—
Nemaha Uplift	2,334	1.6%	41.4%	—	—	—	—
Sedgwick Basin	1,530	3.1%	78.4%	—	—	—	—
Southwestern Wyoming	560	1.0%	—	—	—	—	—
Denver Basin	480	9.1%	—	—	—	—	—
Appalachian Basin	416	8.9%	6.0%	—	—	—	—
Other	438	5.4%	10.3%	147	171	147	163
Total	1,211,333	4.1%	24.0%	192	275	182	245

Note: Numbers may not add up to total amounts due to rounding.

(1) The basins and regions shown in the table are consistent with USGS petroleum-province delineations.

(2) Average royalty interest is equal to the weighted-average percentage of production or revenues (before operating costs) that we are entitled to on a tract-by-tract basis in the basin.

(3) The average percent leased reflects the weighted average of our leased acres relative to our total acreage on a tract-by-tract basis in the basin.

Table of Contents

(4) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each basin for periods in which we have not received sufficient production data from our operators.

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

(6) "Value-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of "oil equivalent," which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

ORRIs

The following table sets forth information about our ORRIs:

			Average Daily Production (Boe/d)			
			6:1(3)(4)		20:1(3)(5)	
USGS Petroleum Province(1)	Acres	Average Royalty Interest(2)	Year Ended December 31, 2013	Six Months Ended June 30, 2014	Year Ended December 31, 2013	Six Months Ended June 30, 2014
North-Central Montana	457,602	2.5%	42	38	13	11
Anadarko Basin	182,096	2.6%	242	259	106	110
Western Gulf (onshore)	88,138	4.4%	123	168	90	126
Powder River Basin	74,794	1.5%	50	53	20	21
Southwestern Wyoming	70,607	2.1%	632	593	196	178
Louisiana-Mississippi Salt Basins	65,610	5.3%	785	509	253	155
Permian Basin	61,677	1.8%	67	71	50	47
Michigan Basin	56,178	1.0%	24	21	12	10
Uinta-Piceance Basin	55,684	1.6%	37	37	19	19
Bend Arch-Fort Worth Basin	41,072	4.5%	207	160	64	48
Arkoma Basin	36,121	2.3%	24	25	7	7
Williston Basin	30,965	2.1%	53	59	50	52
San Juan Basin	28,187	1.1%	4	4	2	1
East Texas Basin	27,982	5.4%	110	98	37	31
Paradox Basin	23,296	0.6%	3	2	1	1
Northern Alaska	20,039	1.7%	18	33	18	30
Wind River Basin	17,806	1.9%	33	34	12	12
Denver Basin	16,371	2.6%	107	85	60	45
Wyoming Thrust Belt	8,720	1.2%	5	4	2	1
Cambridge Arch-Central Kansas Uplift	5,762	3.8%	4	4	4	3
Other	29,915	2.3%	903	920	327	327
Total	1,398,621	2.6%	3,473	3,176	1,343	1,235

Note: Numbers may not add up to total amounts due to rounding.

(1) The basins and regions shown in the table are consistent with USGS petroleum-province delineations.

(2) Average royalty interest is equal to the weighted-average percentage of production or revenues (before operating costs) that we are entitled to on a tract-by-tract basis in the basin.

(3) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each basin for periods in which we have not received sufficient production data from our operators.

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

(5) "Value-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of "oil equivalent," which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

Working Interests

The following table sets forth information about our non-operated working interests:

			Average Daily Production(Boe/d)			
			6:1(3)(4)		20:1(3)(5)	
USGS Petroleum Province(1)	Gross Acres(2)	Net Acres(2)	Year Ended December 31, 2013	Six Months Ended June 30, 2014	Year Ended December 31, 2013	Six Months Ended June 30, 2014
East Texas Basin	127,885	32,426	1,429	1,275	455	410
Western Gulf (onshore)	117,148	17,659	830	703	470	385
Anadarko Basin	62,799	21,686	1,557	1,445	690	611
Bend Arch-Fort Worth Basin	56,001	13,408	155	134	47	41
Louisiana-Mississippi Salt Basins	55,652	7,287	3,066	2,200	972	707
Williston Basin	54,693	7,821	783	1,148	725	1,045
Denver Basin	20,533	1,708	4	4	4	4
Southwestern Wyoming	15,458	2,492	8	6	3	2
Michigan Basin	13,287	1,330	6	5	2	2
Powder River Basin	11,507	2,535	61	58	54	50
Permian Basin	8,791	4,980	159	192	92	129
Arkoma Basin	8,158	1,661	417	322	125	97
Wyoming Thrust Belt	3,979	3,366	—	—	—	—
San Juan Basin	3,442	1,575	10	10	3	3
North-Central Montana	2,280	605	1	1	0	0
Wind River Basin	2,000	935	—	—	—	—
Paradox Basin	520	280	5	5	2	2
Southern Oklahoma	430	92	138	135	67	65
Cherokee Platform	393	163	14	7	10	5
Illinois Basin	240	23	—	—	—	—
Other	1,370	1,218	129	76	95	50
Total	566,566	123,251	8,772	7,727	3,814	3,608

Note: Numbers may not add up to total amounts due to rounding.

(1) The basins and regions shown in the table are consistent with USGS petroleum-province delineations.

(2) Excludes acreage that is not quantifiable due to incomplete seller records.

(3) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each basin for periods in which we have not received sufficient production data from our operators.

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

Table of Contents

(5) "Value-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of "oil equivalent," which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

Wells

The following table sets forth information about our mineral-and-royalty-interest and working-interest wells:

Mineral and Royalty Interests		Working Interests	
USGS Petroleum Province(1)	**Well Count(2)**	**USGS Petroleum Province(1)**	**Well Count(2)**
Permian Basin	17,985	Anadarko Basin	2,552
Anadarko Basin	3,214	Uinta-Piceance Basin	1,115
Western Gulf (onshore)	2,140	Permian Basin	717
Louisiana-Mississippi Salt Basins	2,138	East Texas Basin	516
East Texas Basin	2,051	Western Gulf (onshore)	475
Williston Basin	1,958	Arkoma Basin	465
Uinta-Piceance Basin	1,363	Southern Oklahoma	416
Arkoma Basin	1,275	Louisiana-Mississippi Salt Basins	405
Bend Arch-Fort Worth Basin	1,106	Williston Basin	384
Michigan Basin	871	Bend Arch-Fort Worth Basin	231
Southwestern Wyoming	660	Nemaha Uplift	176
Los Angeles Basin	589	Appalachian Basin	96
Appalachian Basin	542	Ventura Basin	67
Cherokee Platform	500	Michigan Basin	62
San Juan Basin	490	Powder River Basin	55
North-Central Montana	485	Cherokee Platform	12
Wyoming Thrust Belt	376	Paradox Basin	7
Powder River Basin	336	Black Warrior Basin	4
Denver Basin	307	Denver Basin	4
Nemaha Uplift	268	Southwestern Wyoming	4
Other	1,164	Other	2
Total	39,818	**Total**	7,765

(1) The basins and regions shown in the table are consistent with USGS petroleum-province delineations.
(2) We own both mineral and royalty interests and working interests in 2,997 of the wells shown in each column above.

Interests by Resource Play

The following tables present information about our mineral-and-royalty-interest and non-operated working-interest acreage, production, and well count by resource play. As with the acreage shown for the basins above, we may own more than one type of interest in the same tract of land. Consequently, some of the acreage shown for one type of interest below may also be included in the acreage shown for another type of interest.

Mineral Interests

The following table sets forth information about our mineral interests:

				Average Daily Production (Boe/d)			
				6:1(4)(5)		20:1(4)(6)	
Resource Play(1)	Acres	Average Ownership Percent(2)	Average Percent Leased(3)	Year Ended December 31, 2013	Six Months Ended June 30, 2014	Year Ended December 31, 2013	Six Months Ended June 30, 2014
Bakken Shale	318,990	18.3%	69.0%	1,038	1,109	946	1,023
Three Forks	296,689	18.1%	72.3%	483	565	442	517
Haynesville Shale	274,996	68.4%	83.4%	4,136	3,059	1,254	927
Marcellus Shale	253,536	18.3%	50.5%	50	74	15	22
Canyon Lime	232,381	31.9%	48.8%	—	—	—	—
Bossier Shale	213,276	71.0%	80.9%	1,019	644	306	193
Tuscaloosa Marine Shale	181,560	64.5%	42.2%	1	1	1	1
Granite Wash	110,654	15.8%	98.8%	272	255	118	114
Fayetteville Shale	76,539	54.7%	75.7%	1,413	1,666	424	500
Barnett Shale	62,171	16.0%	57.0%	298	236	97	77
Eagle Ford Shale	47,683	18.8%	81.1%	941	1,304	788	1,094
Wolfcamp-Delaware	44,855	15.8%	56.6%	72	136	60	121
Wolfcamp-Midland	36,909	3.7%	99.7%	29	6	25	6

(1) The plays above have been delineated based on information from the EIA, the USGS, state agencies, or according to areas of the most active industry development.

(2) Ownership interest is equal to the percentage that our undivided ownership interest in a tract bears to the entire tract. The per-play average ownership interests shown above reflect the weighted average of our ownership interests in all tracts in the play. Our weighted-average mineral royalty for all of our mineral interests is approximately 20%, which may be multiplied by our ownership interest to approximate the average royalty interest in our mineral and royalty interests.

(3) The average percent leased reflects the weighted average of our leased acres relative to our total acreage on a tract-by-tract basis in the play.

(4) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each play for periods in which we have not received sufficient production data from our operators.

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

(6) "Value-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of "oil equivalent," which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

Table of Contents

NPRIs

The following table sets forth information about our NPRIs:

				Average Daily Production(Boe/d)			
				6:1(4)(5)		20:1(4)(6)	
Resource Play(1)	Acres	Average Royalty Interest(2)	Average Percent Leased(3)	Year Ended December 31, 2013	Six Months Ended June 30, 2014	Year Ended December 31, 2013	Six Months Ended June 30, 2014
Bakken Shale	35,261	1.4%	42.9%	18	29	16	27
Three Forks	32,442	1.3%	45.8%	13	22	12	19
Haynesville Shale	7,078	4.2%	97.1%	—	—	—	—
Marcellus Shale	—	—	—	—	—	—	—
Canyon Lime	—	—	—	—	—	—	—
Bossier Shale	2,096	2.7%	60.2%	—	—	—	—
Tuscaloosa Marine Shale	4,081	2.1%	—	—	—	—	—
Granite Wash	4,122	1.0%	—	—	—	—	—
Fayetteville Shale	—	—	—	—	10	—	3
Barnett Shale	4,644	2.7%	—	2	3	1	1
Eagle Ford Shale	85,063	1.5%	22.6%	—	12	—	10
Wolfcamp-Delaware	18,825	6.3%	25.5%	—	2	—	2
Wolfcamp-Midland	38,513	1.4%	100.0%	—	—	—	—

(1) The plays above have been delineated based on information from the EIA, the USGS, state agencies, or according to areas of the most active industry development.

(2) Average royalty interest is equal to the weighted-average percentage of production or revenues (before operating costs) that we are entitled to on a tract-by-tract basis for the given area.

(3) The average percent leased reflects the weighted average of our leased acres relative to our total acreage on a tract-by-tract basis in the play.

(4) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each play for periods in which we have not received sufficient production data from our operators.

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

(6) "Value-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of "oil equivalent," which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

Table of Contents

ORRIs

The following table sets forth information about our ORRIs:

Resource Play(1)	Acres	Average Royalty Interest(2)	Average Daily Production (Boe/d) 6:1(3)(4) Year Ended December 31, 2013	6:1(3)(4) Six Months Ended June 30, 2014	20:1(3)(5) Year Ended December 31, 2013	20:1(3)(5) Six Months Ended June 30, 2014
Bakken Shale	12,930	1.2%	22	26	21	25
Three Forks	12,250	1.2%	18	17	17	16
Haynesville Shale	53,191	6.1%	681	463	204	139
Marcellus Shale	1,002	7.0%	74	66	22	20
Canyon Lime	—	—	—	—	—	—
Bossier Shale	47,124	5.4%	62	33	19	10
Tuscaloosa Marine Shale	22,674	10.5%	—	—	—	—
Granite Wash	87,920	1.9%	154	180	67	77
Fayetteville Shale	12,160	4.5%	—	—	—	—
Barnett Shale	35,872	4.9%	204	162	62	49
Eagle Ford Shale	33,532	2.9%	50	87	48	83
Wolfcamp-Delaware	1,080	0.7%	—	5	—	3
Wolfcamp-Midland	14,804	0.8%	7	—	4	—

(1) The plays above have been delineated based on information from the EIA, the USGS, state agencies, or according to areas of the most active industry development.

(2) Average royalty interest is equal to the weighted-average percentage of production or revenues (before operating costs) that we are entitled to on a tract-by-tract basis in this play.

(3) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each play for periods in which we have not received sufficient production data from our operators.

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

(5) “Value-equivalent” production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of “oil equivalent,” which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

Working Interests

The following table sets forth information about our working interests.

			Average Daily Production(Boe/d)			
			6:1(3)(4)		20:1(3)(5)	
Resource Play(1)	Gross Acres(2)	Net Acres(2)	Year Ended December 31, 2013	Six Months Ended June 30, 2014	Year Ended December 31, 2013	Six Months Ended June 30, 2014
Bakken Shale	49,799	7,075	484	654	448	595
Three Forks	50,000	6,752	270	386	250	359
Haynesville Shale	168,451	38,256	3,913	3,237	1,174	971
Marcellus Shale	—	—	4	3	1	1
Canyon Lime	—	—	—	—	—	—
Bossier Shale	144,619	35,002	263	189	79	57
Tuscaloosa Marine Shale	—	—	—	—	—	—
Granite Wash	5,194	1,364	756	748	310	290
Fayetteville Shale	—	—	36	33	11	10
Barnett Shale	48,282	12,440	150	140	45	42
Eagle Ford Shale	235	118	—	—	—	—
Wolfcamp-Delaware	520	89	5	21	3	18
Wolfcamp-Midland	160	4	9	10	4	4

(1) The plays above have been delineated based on information from the EIA, the USGS, state agencies, or according to areas of the most active industry development.
(2) Excludes acreage that is not quantifiable due to incomplete seller records.
(3) For the year ended December 31, 2013, production volumes represent actual production by production month during the period. For the six months ended June 30, 2014, we have provided actual production where possible and have allocated accrued volumes to each play for periods in which we have not received sufficient production data from our operators.
(4) “Btu-equivalent” production volumes are presented on an oil-equivalent basis using a conversion factor of six Mcf of natural gas per barrel of “oil equivalent,” which is based on approximate energy equivalency and does not reflect the price or value relationship between oil and natural gas.
(5) “Value-equivalent” production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of “oil equivalent,” which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues.

Estimated Proved Reserves

Evaluation and Review of Estimated Proved Reserves

The information included in this prospectus relating to our estimated proved oil and natural gas reserves is based upon a reserve report prepared by Pressler, a third-party petroleum engineering firm, as of December 31, 2013.

Pressler provides domestic petroleum property analysis services for energy clients, financial organizations, and government agencies. Pressler was founded in 1991 and performs petroleum-engineering consulting services under Texas Board of Professional Engineers Firm (Registration No. 7807). Within Pressler, the technical person primarily responsible for preparing the estimates set forth in the Pressler summary reserve report incorporated herein is Mr. Jim R. McReynolds, P.E. Mr. McReynolds has been practicing petroleum-engineering consulting at Pressler since 1993. Mr. McReynolds is a Licensed Professional Engineer in the State of Texas (Registration No. 73027) and has over 35 years of practical experience in petroleum engineering, the vast majority of which is in the estimation and evaluation of reserves. He graduated from the University of Oklahoma in 1977 with a Bachelor of Science Degree in Petroleum Engineering. As technical principal, Mr. McReynolds meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering evaluations as well as in applying SEC and other industry reserves definitions and guidelines. A copy of Pressler's estimated proved reserve report as of December 31, 2013 is attached as an exhibit to the registration statement of which this prospectus forms a part.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our third-party reserve engineers to ensure the integrity, accuracy, and timeliness of the data used to calculate our estimated proved reserves. Our internal technical team members met with our third-party reserve engineers periodically during the periods covered by the above referenced reserve report to discuss the assumptions and methods used in the reserve estimation process. We provided historical information to the third-party reserve engineers for our properties, such as oil and natural gas production, well test data, realized commodity prices, and operating and development costs. We also provided ownership interest information with respect to our properties. Brock Morris, our Senior Vice President, Engineering and Geology, is primarily responsible for overseeing the preparation of all of our reserve estimates. Mr. Morris is a petroleum engineer with approximately 29 years of reservoir-engineering and operations experience, and our engineering and geoscience staff has an average of approximately 22 years of industry experience.

The preparation of our historical proved reserve estimates were completed in accordance with our internal control procedures. Throughout the year, our technical team met with Pressler to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data used in the reserves evaluation software as well as reviews by our internal engineering staff and management, which include the following:

- Comparison of historical operating expenses from the lease operating statements to the operating costs input in the reserves database;
- Review of working interests and net revenue interests in the reserves database against our well ownership system;
- Review of historical realized commodity prices and differentials from index prices compared to the differentials used in the reserves database;
- Review of capital costs assumptions to actual historical capital costs;
- Review of actual historical production volumes compared to projections in the reserve report;
- Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President, Engineering and Geology; and
- Review of preliminary reserve estimates by our President and Chief Executive Officer with our internal technical staff.

Estimation of Proved Reserves

In accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" means deterministically, the quantities of oil and/or natural gas are much more likely to be achieved than not, and probabilistically, there should be at least a 90% probability of recovering volumes equal to or exceeding the estimate. All of our estimated proved reserves as of December 31, 2013 are based on deterministic methods. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by using reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated net proved reserves, Pressler employed technologies including, but not limited to, electrical logs, radioactivity logs, core analyses, geologic maps, and available down hole pressure and production data, seismic data, and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. In addition to assessing reservoir continuity, geologic data from well logs, core analyses, and seismic data were used to estimate original oil and natural gas in place. Recovery factors were determined utilizing reservoir simulation or analogy with similar reservoirs where similar drilling and completion techniques have been employed.

Summary of Estimated Proved Reserves

The following table presents our estimated proved oil and natural gas reserves as of December 31, 2013:

	December 31, 2013
Estimated proved developed reserves:	
Oil (MBbls)	17,290
Natural gas (MMcf)	232,777
Total (MBoe)(1)	56,086
Estimated proved undeveloped reserves:	
Oil (MBbls)	1,659
Natural gas (MMcf)	7,183
Total (MBoe)(1)	2,856
Estimated proved reserves:	
Oil (MBbls)	18,949
Natural gas (MMcf)	239,960
Total (MBoe)(1)	58,942
Percent proved developed	95.2%

(1) Estimates of reserves as of December 31, 2013 were prepared using oil and natural gas prices equal to the unweighted arithmetic average of the first-day-of-the-month market price for each month in the period January through December 2013. For oil volumes, the average WTI Cushing, Oklahoma spot oil price of $96.78 per barrel is used for all the properties. These average prices are adjusted for quality, transportation fees, and regional price differentials. For natural gas volumes, the average Henry Hub price of $3.67 per MMBTU is adjusted for energy content transportation fees and regional price differentials. Natural gas prices are also adjusted to account for NGL revenue since there is not sufficient data to account for NGLs separately in the reserves estimates. The adjusted prices are $94.84 per Bbl of oil and $3.74 per Mcf of natural gas. Estimated proved reserves are presented on an oil-equivalent basis using a conversion of six Mcf per barrel of “oil equivalent.” This conversion is based on energy equivalence and not price or value equivalence. If a price equivalent conversion based on these twelve-month average prices for the year ended December 31, 2013 was used, the conversion factor would be approximately 26 Mcf per Bbl of oil rather than six Mcf per Bbl of oil. In this prospectus, we supplementally provide “value-equivalent” production information or volumes presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of “oil equivalent,” which is the conversion factor we use in our business and which we believe represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues. Reserve estimates do not include any value for probable

or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses, and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing, and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices, and future production rates and costs. Please read “Risk Factors.”

Additional information regarding our estimated proved reserves can be found in the notes to our consolidated financial statements included elsewhere in this prospectus and the estimated proved reserve report as of December 31, 2013, which is included as an exhibit to the registration statement of which this prospectus forms a part.

Estimated Proved Undeveloped Proved Reserves

As of December 31, 2013, our PUDs were composed of 1,659 MBbls of oil and 7,183 MMcf of natural gas, for a total of 2,856 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during the year ended December 31, 2013 (in MBoe):

Balance, December 31, 2012	**5,580**
Acquisitions of reserves	24
Extensions and discoveries	2,391
Revisions of previous estimates	(643)
Transfers to estimated proved developed	(4,497)
Balance, December 31, 2013	**2,855**

Extensions and discoveries of 2,391 MBoe during the year ended December 31, 2013, resulted primarily from drilling and capital expenditures in the Bakken Shale, Haynesville Shale, Granite Wash, and Southeast Texas Wilcox plays.

Costs incurred relating to the development of locations that were classified as PUDs at December 31, 2012 were $22.4 million during the year ended December 31, 2013. Additionally, during 2013, we spent approximately $40.8 million drilling and completing other in-field wells which were not classified as PUDs as of December 31, 2012. Estimated future development costs relating to the development of PUDs at December 31, 2013 were projected to be approximately $21.3 million in the year ended December 31, 2014. As we continue to participate in new wells on our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years. All of our PUD drilling locations as of December 31, 2013 are scheduled to be drilled within five years or less from the date the reserves were initially booked as proved undeveloped reserves.

We generally do not have our operators’ approved development plans. As a result, our proved undeveloped reserve estimates are limited to those relatively few locations for which we have received and approved an AFE. As of December 31, 2013, approximately 4.9% of our total proved reserves were classified as PUDs.

Table of Contents

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding production of oil and natural gas and certain price and cost information for each of the periods indicated:

	For the Year Ended December 31, 2011	2012	2013	For the Six Months Ended June 30, 2014
Production Data:				
Oil and condensate (Bbls)	1,849,808	2,173,117	2,626,018	1,323,126
Natural gas (Mcf)	51,467,152	52,965,439	45,400,235	20,228,480
Total (Boe)(6:1)(1)	10,427,667	11,000,691	10,192,724	4,694,539
Average daily production (Boe/d)(6:1)	28,569	30,057	27,925	25,937
Total (Boe)(20:1)(2)	4,423,166	4,821,389	4,896,030	2,334,550
Average daily production (Boe/d)(20:1)	12,118	13,209	13,414	12,898
Average Realized Sale Prices(3):				
Oil and condensate (per Bbl)	$ 95.35	$ 93.00	$ 96.25	$ 94.15
Natural gas and natural gas liquids (per Mcf)	4.59	3.15	4.07	5.47
Average Unit Cost per Boe(6:1):				
Lease operating expense and other	$ 2.31	$ 1.87	$ 2.09	$ 2.06
Production and ad valorem taxes	3.45	3.33	4.20	4.56
Total (per Boe)	$ 5.75	$ 5.20	$ 6.29	$ 6.62

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

(2) "Value-equivalent" production volumes are presented on an oil-equivalent basis using a conversion factor of 20 Mcf of natural gas per barrel of "oil equivalent," which is the conversion factor we use in our business. We believe this conversion factor represents an estimation of value equivalence over time and better correlates with the respective contribution of oil and natural gas to our revenues

(3) Excludes the effect of commodity-derivative instruments.

Productive Wells

Productive wells consist of producing wells, wells capable of production, and exploratory, development, or extension wells that are not dry wells. As of June 30, 2014, we owned mineral and royalty interests in 39,818 productive wells and working interests in 7,765 gross productive wells and 211 net productive wells. We own both mineral and royalty interests and working interests in 2,997 of these wells.

Table of Contents

Acreage

Mineral and Royalty Interests

The following table sets forth information relating to our acreage for our mineral and royalty interests:

State	Developed Acreage	Undeveloped Acreage	Total Acreage
Texas	312,890	3,521,401	3,834,291
Mississippi	6,036	2,317,626	2,323,662
Alabama	2,792	2,025,520	2,028,312
Arkansas	4,887	1,188,336	1,193,223
North Dakota	13,742	854,765	868,507
Nevada	—	792,208	792,208
Florida	—	695,035	695,035
Louisiana	35,335	495,074	530,408
Oklahoma	119,374	350,013	469,386
Montana	20,765	408,373	429,138
Other	82,081	1,223,484	1,305,565
Total	597,901	13,871,835	14,469,736

Note: Numbers may not add up to total amounts due to rounding.

The following table sets forth information relating to our acreage for our NPRIs:

State	Developed Acreage	Undeveloped Acreage	Total Acreage
Texas	194,759	623,534	818,293
Montana	12,244	167,206	179,450
Louisiana	11,148	43,748	54,896
Mississippi	9,787	33,766	43,554
North Dakota	15,171	20,585	35,756
Arkansas	3,974	15,207	19,180
Wyoming	1,360	16,840	18,200
New Mexico	14,449	800	15,249
Oklahoma	7,068	4,828	11,897
Kansas	8,722	2,663	11,384
Other	367	3,106	3,473
Total	279,050	932,283	1,211,333

Note: Numbers may not add up to total amounts due to rounding.

Table of Contents

The following table sets forth information relating to our acreage for our ORRIs:

State	Developed Acreage	Undeveloped Acreage	Total Acreage
Montana	294,768	165,674	460,442
Texas	217,923	2,482	220,405
Wyoming	136,279	35,671	171,950
Oklahoma	155,495	4	155,499
Louisiana	71,969	12,164	84,133
Utah	41,790	28,149	69,939
Michigan	55,259	919	56,178
New Mexico	46,631	1,847	48,478
Colorado	28,319	5,111	33,430
Alaska	7,664	12,375	20,039
Other	66,716	11,411	78,127
Total	1,122,814	275,807	1,398,621

Note: Numbers may not add up to total amounts due to rounding.

Working Interests

The following table sets forth information relating to our acreage for our working interests:

State	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
Texas	198,519	42,921	154,526	35,864	353,045	78,784
North Dakota	41,884	6,224	9,009	1,001	50,892	7,225
Louisiana	31,221	4,128	18,754	1,991	49,975	6,119
Wyoming	22,342	4,207	11,443	5,961	33,785	10,168
Colorado	24,215	3,276	202	50	24,417	3,326
Michigan	13,208	1,330	79	—	13,287	1,330
Oklahoma	11,822	2,781	1,355	608	13,177	3,389
Kansas	8,032	6,213	921	—	8,953	6,213
New Mexico	5,997	3,926	520	98	6,517	4,024
South Dakota	2,160	504	880	55	3,040	559
Other	5,847	1,194	3,630	918	9,477	2,113
Total	365,246	76,704	201,319	46,547	566,566	123,251

Note: Numbers may not add up to total amounts due to rounding.

The following table lists the net undeveloped acres, the net acres expiring in the years ending December 31, 2015, 2016, and 2017, and, where applicable, the net acres expiring that are subject to extension options:

Net Undeveloped Acreage	2015 Expirations		2016 Expirations		2017 Expirations	
	Net Acreage without Ext. Opt.	Net Acreage with Ext. Opt.	Net Acreage without Ext. Opt.	Net Acreage with Ext. Opt.	Net Acreage without Ext. Opt.	Net Acreage with Ext. Opt.
46,547	4,896	522	5,360	202	1,605	151

Drilling Results for our Working Interests

The following table sets forth information with respect to the number of wells completed on our properties during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, the quantities of reserves found and the economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	For the Year Ended December 31,			For the Six Months Ended June 30, 2014
	2011	2012	2013	
Gross development wells:				
Productive	221.0	218.0	187.0	81.0
Dry	1.0	—	—	—
Total	222.0	218.0	187.0	81.0
Net development wells:				
Productive	9.0	7.8	8.1	2.8
Dry	—	—	—	—
Total	9.0	7.8	8.1	2.8
Gross exploratory wells:				
Productive	—	—	1.0	—
Dry	—	—	—	—
Total	—	—	1.0	—
Net exploratory wells:				
Productive	—	—	0.1	—
Dry	—	—	—	—
Total	—	—	0.1	—

As of June 30, 2014, we had 61 wells in the process of drilling, completing or dewatering, or shut in awaiting infrastructure that are not reflected in the above table.

Environmental Matters

Oil and natural gas exploration, development, and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. These laws and regulations have the potential to impact production on our properties, which could materially adversely affect our business and our prospects. Numerous federal, state, and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil, and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities, and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent, or remediate pollution from current or former operations, such as plugging abandoned wells or closing earthen pits, result in the suspension or revocation of necessary permits, licenses, and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from operations. The strict, joint and several liability nature of such laws and regulations could impose liability upon our operators, or us as working-interest owners if the operator fails to perform, regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our business and prospects.

Waste Handling

The Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development, and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal, and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development, and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, these wastes typically constitute "solid wastes" that are subject to less stringent non-hazardous waste requirements. However, it is possible that RCRA could be amended or the EPA or state environmental agencies could adopt policies to require oil and gas exploration, development, and production wastes to become subject to more stringent waste handling requirements. Administrative, civil, and criminal penalties can be imposed for failure to comply with waste handling requirements. Any changes in the laws and regulations could have a material adverse effect on our operators' capital expenditures and operating expenses, which in turn could affect production from our properties and adversely affect our business and prospects.

Remediation of Hazardous Substances

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the "Superfund" law, and analogous state laws generally impose strict, joint, and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a contaminated facility (which can include working-interest owners), a former owner or operator of the facility at the time of contamination and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed "responsible parties" may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Oil and gas exploration and production activities on our properties use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold our operators, or us as working-interest owners if the operator fails to perform, responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which these "hazardous substances" have been released.

Water Discharges

The Federal Water Pollution Control Act of 1972, also known as the "Clean Water Act," the SDWA, the Oil Pollution Act ("OPA") and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The Clean Water Act and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. In addition, spill prevention, control, and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges.

The OPA is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil into surface waters.

Noncompliance with the Clean Water Act, or OPA, may result in substantial administrative, civil, and criminal penalties, as well as injunctive obligations.

Air Emissions

The federal Clean Air Act and comparable state laws and regulations regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, in August 2012, the EPA adopted new regulations under the Clean Air Act that established new emission control requirements for oil and natural gas production and processing operations. These laws and regulations may increase the costs of compliance for oil and gas producers and impact production on our properties, and federal and state regulatory agencies can impose administrative, civil, and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Moreover, obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Climate Change

In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment because, according to the EPA, emissions of these gases contribute to warming of the earth’s atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs from certain large stationary sources of GHG emissions. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including certain onshore oil and gas exploration and production facilities.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although the U.S. Congress has not adopted this type of legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce GHG emissions. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry at this time; it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados, and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with production on our properties and increase our costs. Moreover, damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our business.

Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process involves the injection of water, sand, and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Our operators routinely use hydraulic fracturing. The SDWA regulates the underground injection of substances through the Underground Injection Control ("UIC") program. Hydraulic fracturing generally is exempt from regulation under the UIC program, and the hydraulic fracturing process is typically regulated by state oil and gas commissions. The EPA, however, has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program, and issued guidance in February 2014 for hydraulic fracturing activities involving the use of diesel. Additional regulatory actions taken by the EPA include: (i) the issuance an Advanced Notice of Proposed Rulemaking seeking public comment on the agency's intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing; (ii) announcing its intent to develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities, expected in late 2014; (iii) publishing final rules under the federal Clean Air Act that require companies to employ "green completion" technology to address emissions of volatile organic compounds. Also, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity, and handling of flowback water.

Certain governmental reviews also have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, expected to be released in late 2014. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms.

Several states have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, Texas requires oil and natural gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. Regulations require that well operators disclose the list of chemical ingredients subject to the requirements of the Occupational Safety and Health Act, as amended ("OSHA") on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Furthermore, in May 2013, the Texas Railroad Commission issued a "well integrity rule," which updates the requirements for drilling, installing pipe, and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The "well integrity rule" took effect in January 2014. In addition, municipalities in Texas, Colorado, and several other states have adopted, or are in the process of adopting, ordinances restricting or prohibiting hydraulic fracturing within their jurisdictions. The widespread adoption of ordinances limiting hydraulic fracturing could adversely affect our business.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, impacts on drinking water supplies, the use of water and the potential for impacts to surface water, groundwater, and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, these laws could make it more difficult or costly to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing is further regulated at the federal or state level, hydraulic fracturing activities on our properties could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements, and potential increases in costs. These types of legislative changes could cause us and our operators to incur substantial compliance costs, and compliance or the consequences of any failure to comply could have a material adverse effect on our financial condition and our business. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing.

Occupational Safety and Health Act

The OSHA and comparable state laws and regulations govern the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in operations on our properties and that this information be provided to employees, state and local government authorities, and citizens.

Endangered Species

The Endangered Species Act ("ESA") and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Some of our properties may be located in areas that are or may be designated as habitats for endangered or threatened species, and previously unprotected species may later be designated as threatened or endangered in areas where we hold mineral interests. This could cause our operators to incur increased costs arising from species protection measures, delay the completion of exploration and production activities and/or result in limitations on operating activities that could have an adverse impact on our business.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties. After an acquisition, we review the assignments from the seller for scrivener's and other errors and execute and record corrective assignments as necessary.

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the titles to our properties on which we do not have proved reserves. Prior to the acquisition of those properties, our operators conduct a thorough title examination, and we perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. Our operators generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We believe that the title to our assets is satisfactory in all material respects. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions, and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights-of-way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this prospectus.

Competition

The oil and gas business is highly competitive in the exploration for and acquisition of reserves, the acquisition of minerals and oil and gas leases and personnel required to find and produce reserves. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national, or worldwide basis. Certain of our competitors may possess financial or other resources substantially larger than we possess. Our ability to acquire additional minerals and properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Oil and natural gas products compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal, and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations, and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Seasonal Nature of Business

Weather conditions affect the demand for, and prices of, natural gas and can also delay drilling activities, disrupting our overall business plans. Demand for natural gas is typically higher during the winter, resulting in higher natural gas prices for our natural gas production during our first and fourth quarters. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions can limit drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. Due to these seasonal fluctuations, our results of operations for individual quarterly periods may not be indicative of the results that we may realize on an annual basis.

Employees

We are managed and operated by the board of directors and executive officers of our general partner. All of our employees, including our executive officers, are employees of Black Stone Management. As of June 30, 2014, Black Stone Management had 116 full-time employees. None of Black Stone Management’s employees are represented by labor unions or covered by any collective bargaining agreements.

Facilities

Our principal office location is in Houston, Texas and consists of 57,481 square feet of leased space.

Legal Proceedings

Although we may, from time to time, be involved in various legal claims arising out of our operations in the normal course of business, we do not believe that the resolution of these matters will have a material adverse impact on our financial condition or results of operations.

MANAGEMENT

Management

We are managed and operated by the board of directors and executive officers of our general partner, the latter of whom are employed by Black Stone Management, our administrative manager and wholly owned subsidiary. The executive officers of our general partner will manage the day-to-day affairs of our business.

In connection with the closing of this offering, we will complete a series of transactions pursuant to which, among other things, BSMC and BSNR will become our wholly owned subsidiaries. Please read “Summary—Formation Transactions and Structure.” Our partnership agreement provides that our limited partners holding common units have the right to nominate and vote in the election of directors to the board of directors of our general partner. Except with respect to matters requiring preferred unitholder super majority approval, preferred unitholder majority approval or the approval of a preferred unitholder, at each meeting of the limited partners (or pursuant to any action by written consent), with respect to any and all matters presented to the limited partners for their action or consideration, each preferred unitholder is entitled to vote as a single class with the common units on an “as-converted” basis, meaning that each preferred unit has a number of votes equal to the number of common units into which the preferred unit is convertible at the time of a vote or consent. Please read “Description of Our Preferred Units—Voting; Waiver.”

Upon the closing of this offering, we expect that the board of directors of our general partner will have directors, of whom will be independent as defined under the independence standards established by the NYSE and the Exchange Act. will serve as the initial independent member of the board of directors of our general partner. In accordance with the rules of the NYSE, the board of directors of our general partner must have one additional independent member within 90 days of the effective date of the registration statement of which this prospectus forms a part and one additional independent member within one year of the effective date, which would bring the total number of directors on the board of directors of our general partner to . The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating and corporate governance committee although we have determined to establish these committees. However, our general partner is required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act, subject to the transitional relief during the one-year period following completion of this offering.

Our partnership agreement provides that an annual meeting of the limited partners for the election of directors to the board of directors of our general partner will be held at the date and time as may be fixed from time to time by our general partner. At each annual meeting, the limited partners authorized to vote will elect by a plurality of the votes cast at the meeting persons to serve as directors on the board of directors of our general partner who are nominated in accordance with the provisions of our partnership agreement. At all elections of the board of directors of our general partner, each limited partner authorized to vote will be entitled to cumulate his or her votes and give one candidate, or divide among any number of candidates, a number of votes equal to the product of (x) the number of units held by the limited partner, multiplied by (y) the number of directors to be elected at the meeting.

Executive Officers and Directors of Our General Partner

The following table shows information for the executive officers and directors of our general partner upon the consummation of this offering. Executive officers serve at the discretion of the board. Directors hold office until their successors are duly elected and qualified. There are no family relationships among any of our directors or executive officers.

Name	Age (as of June 30, 2014)	Position With Our General Partner
Thomas L. Carter, Jr.	63	President, Chief Executive Officer and Chairman
Marc Carroll	44	Senior Vice President and Chief Financial Officer
Holbrook F. Dorn	38	Senior Vice President, Business Development
Brock Morris	50	Senior Vice President, Engineering and Geology
Steve Putman	39	Senior Vice President, General Counsel, and Secretary
Allan Skov	50	Senior Vice President, Corporate Services, and Chief Information Officer
Mark L. Harmon	53	Senior Vice President, Exploration
Mark E. Robinson	62	Vice President, Land and Legal
Samuel A. Crabb	51	Vice President of Accounting and Controller
		Director
		Director
		Director

Thomas L. Carter, Jr. Mr. Carter is the founder of BSMC and has served as President, Chief Executive Officer and Chairman of our general partner since 1998. Prior to his latest position with BSMC, Mr. Carter served as Managing General Partner of W.T. Carter & Bro. from 1987 to 1992 and Black Stone Energy Company from 1980 to present, both of which preceded our general partner. Mr. Carter founded Black Stone Energy Company, BSMC's operating and exploration subsidiary, in 1980. From 1978 to 1980, Mr. Carter served as a lending officer in the Energy Department of Texas Commerce Bank in Houston, Texas, after serving in various other roles from 1975. Mr. Carter received M.B.A. and B.B.A. degrees from the University of Texas at Austin. Mr. Carter has been a director of Carrizo Oil & Gas Inc. since 2005. He has served as a Trustee at Episcopal High School in Houston, Texas since 2004, and as a Trustee of St. Edward's University since 2009. Mr. Carter has been a Trustee of the Lawrenceville School since 1998, and was elected to a four year term as President of the Board of Trustees in 2013. Mr. Carter also serves on the University of Texas at Austin Internal Audit Committee, the University Lands Advisory Board, and the Ripley Foundation board.

Mr. Carter's extensive industry and executive management experience and his background in finance qualify him to serve on the board of directors of our general partner.

Marc Carroll. Mr. Carroll has served as Senior Vice President and Chief Financial Officer of our general partner since January 2008. Mr. Carroll previously served as Vice President of Finance, after beginning his employment with our general partner as the Manager of Finance in September 2004. Before joining BSMC, Mr. Carroll was employed by El Paso Corporation from July 1998 to August 2004 as a Natural Gas Trader, Manager of Business Development, and Manager of Financial Planning and Analysis. Mr. Carroll held several positions at The Coastal Corporation and Energy Ventures Inc. (predecessor to Weatherford International) from 1992 to 1996. Mr. Carroll received a B.B.A. in Accounting and a B.B.A. in Business Analysis from Texas A&M University, and received his M.B.A. from Rice University. Mr. Carroll is a Certified Public Accountant.

Holbrook F. Dorn. Mr. Dorn has served as Senior Vice President, Business Development of our general partner since 2010. Prior to serving as Senior Vice President, Mr. Dorn served as Vice President, Business Development from 2008 through 2010. He was also previously employed at BSMC from 2002 to 2004 as an Associate in Business Development. Mr. Dorn also served at Touradji Capital Management, LP from 2006 to 2008. Mr. Dorn received a B.B.A. from the University of Texas at Austin and an M.B.A. from Columbia University.

Allan Skov. Mr. Skov has served as Senior Vice President, Corporate Services, and Chief Information Officer of our general partner since 2013. Prior to his current role, Mr. Skov held the position of Chief Information Officer of our general partner beginning in 2009. Before he joined BSMC, Mr. Skov served as Vice President Information Technology of DCP Midstream, Duke Energy's joint venture with ConocoPhillips, from 2003 to 2008 and held the position of Director IT Strategies and Consulting at Duke Energy from 2001 to 2003. He also served as Chief Information Officer of Newfoundland Power Inc. from 1997 to 2001 and held various positions in finance, human resources, customer service, and information technology at Union Gas Limited from 1986 to 1997. Mr. Skov received Bachelor of Commerce and M.B.A. degrees from the University of Windsor in Ontario, Canada.

Brock Morris. Mr. Morris has served as Senior Vice President, Engineering and Geology of our general partner since 2013. From 2006 to 2013, Mr. Morris served as Managing Director—Exploration and Production of Quintana Capital Group and its energy-focused private equity funds, overseeing all upstream oil and gas investments. He served as Vice President, Exploration and Production of Quintana Minerals Corporation from 1995 to 2006 and as in various engineering and management roles, including Operations Manager at Quintana Petroleum Corporation from 1985 to 1995. Mr. Morris received a B.S. in Petroleum Engineering from Texas A&M University.

Steve Putman. Mr. Putman has served as Senior Vice President, General Counsel, and Secretary of our general partner since 2013. Prior to joining BSMC, Mr. Putman was Managing Director and General Counsel of Quintana Capital Group from 2008 to 2013 and Vice President, General Counsel, and Secretary of Quintana Maritime Limited from 2005 to 2008. He also worked as an associate at Vinson & Elkins L.L.P. from 2001 to 2005 and Mayer Brown LLP from 2000 to 2001. Mr. Putman received a B.A. from the University of Texas at Austin and a J.D. from the University of Chicago. He is licensed to practice law in the states of Texas and Illinois.

Mark L. Harmon. Mr. Harmon has served as Senior Vice President, Exploration of our general partner since 2010. Mr. Harmon joined our general partner in 2004 after it acquired International Paper's minerals from Unocal. From 2004 to 2010, Mark served in three capacities including Senior Geologist, Exploration Manager, and Vice President of Exploration. Prior to joining BSMC, Mr. Harmon served as a senior geologist at Pure Resources LLC and Unocal Corporation from 2001 to 2004. From 1990 until 2001, Mr. Harmon worked as a Senior Geologist with IP Petroleum Company. He began his career in 1983 as a Geologist at First Energy Corporation. Mr. Harmon received his B.S. degree in Geology from Louisiana Tech University.

Mark E. Robinson. Mr. Robinson has served as Vice President, Land and Legal of our general partner since 2004. Prior to joining BSMC, Mr. Robinson served as a Senior Attorney of Sonat Exploration Company from 1991 to 2000, when Sonat merged with El Paso Corporation. He remained at El Paso Corporation until December 2004. Prior to joining Sonat, Mr. Robinson worked in private law practice in Louisiana for 12 years. He received a J.D. from Louisiana State University in 1978. Mr. Robinson is licensed to practice law in the states of Louisiana and Texas.

Samuel A. Crabb. Mr. Crabb has served as Vice President of Accounting and Controller of our general partner since January 2010. Mr. Crabb joined our general partner in July 1991, and from 1991 to 2010, served in three capacities including Senior Accountant, Accounting Manager and Controller. Prior to joining BSMC, Mr. Crabb served as a CPA at Tinsley and Tinsley, PC an independent accounting firm. Mr. Crabb received a B.B.A. in Accounting from the University of Houston and is a Certified Public Accountant.

Director Independence

In accordance with the rules of the NYSE, our general partner must have at least one independent director by the time our common units are first listed on the NYSE, one additional independent member within 90 days of the effective date of the registration statement of which this prospectus forms a part, and one additional independent member within one year of the effective date of the registration statement.

Table of Contents

Committees of the Board of Directors

The board of directors of our general partner will have an audit committee, a compensation committee, a nominating and governance committee, and a conflicts committee.

Audit Committee

We are required to have an audit committee of at least three members, and all its members are required to meet the independence and experience standards established by the NYSE and Rule 10A-3 promulgated under the Exchange Act, subject to certain transitional relief during the one-year period following consummation of this offering as described above.   will serve as the initial members of the audit committee. The audit committee will assist the board of directors in its oversight of the (i) integrity of our financial statements, (ii) our compliance with legal and regulatory requirements, (iii) qualifications and independence of our independent registered public accounting firm, and (iv) performance of our internal audit function and independent registered public accounting firm. The audit committee will have the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee and our management, as necessary.

Compensation Committee

Because we are a limited partnership, we are not required by the rules of the NYSE to have a compensation committee or, in the event we choose to establish one, a compensation committee composed entirely of independent directors. However, we nevertheless expect that we will have a compensation committee following the completion of this offering. The compensation committee will review and determine the compensation for the executive officers of our general partner and will review and make recommendations to the board of directors of our general partner regarding director compensation. The compensation committee will also administer our incentive compensation and equity-based benefit plans.   will serve as the initial members of the compensation committee.

Nominating & Governance Committee

Because we are a limited partnership, we are not required by the rules of the NYSE to have a nominating and governance committee or, in the event we choose to establish one, a nominating and governance committee composed entirely of independent directors. However, we nevertheless expect that we will have a nominating and governance committee following the completion of this offering. The nominating and governance committee will identify individuals qualified to serve on the board of directors of the general partner and recommend director nominees for each annual meeting of unitholders or for appointment to fill vacancies, oversee our governance policies, including developing and recommending to the board of directors of the general partner a set of corporate governance guidelines, and oversee the evaluation of the board and its committees.   will serve as the initial members of the nominating and governance committee.

Conflicts Committee

We expect that at least one independent member of the board of directors of our general partner will serve on a conflicts committee to review specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The conflicts committee will determine if the resolution of the conflict of interest is, in its subjective belief, not adverse to our interest. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates and must meet the independence standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors, along with other requirements in our partnership agreement. Any matters approved by the conflicts committee will be conclusively deemed to be approved by us and all of our partners and not a breach by our general partner of any duties or contractual obligations it may owe us or our unitholders.

Procedures for Review, Approval, and Ratification of Transactions with Related Persons

We expect that the board of directors of our general partner will adopt policies for the review, approval, and ratification of transactions with related persons. We anticipate the board will adopt a written code of business conduct and ethics, under which a director would be expected to bring to the attention of the chief executive officer or the board any conflict or potential conflict of interest that may arise between the director or any affiliate of the director, on the one hand, and us or our general partner on the other. The resolution of any conflict or potential conflict should, at the discretion of the board in light of the circumstances, be determined by a majority of the disinterested directors.

Upon our adoption of our code of business conduct and ethics, we would expect that any executive officer will be required to avoid conflicts of interest unless approved by the board of directors of our general partner.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

We are providing compensation disclosure that satisfies the requirements applicable to emerging growth companies, as defined in the JOBS Act.

Summary Compensation Table

The table below provides information concerning the annual compensation of our named executive officers (our "Named Executive Officers" or "NEOs") for the fiscal year ended December 31, 2013.

Name and Principal Position	Year	Salary ($)(2)	Unit Awards ($)(3)	Non-Equity Incentive Plan Compensation ($)(4)	All Other Compensation ($)(5)	Total ($)
Thomas L. Carter, Jr. *(Chairman of the Board of Directors and Chief Executive Officer)*	2013	$650,000	$2,518,750	$ 1,579,841	$ 25,055	$ 4,773,646
Marc Carroll *(Senior Vice President and Chief Financial Officer)*	2013	$355,000	$1,125,000	$ 669,075	$ 12,750	$ 2,161,825
Holbrook F. Dorn *(Senior Vice President, Business Development)*	2013	$311,666	$ 975,000	$ 549,864	—	$ 1,836,530
Hallie A. Vanderhider(1) *(Former President and Chief Operating Officer)*	2013	$227,931	—	$ 552,083	$ 2,412,781	$ 3,192,795

(1) Ms. Vanderhider resigned from her employment with us effective as of May 15, 2013.

(2) Amounts include elective deferrals made by our Named Executive Officers under the Black Stone Energy Company 401(k) Plan (the "401(k) Plan").

(3) Amounts reflect the grant date fair value of common units in our predecessor and common shares in our general partner granted on January 1, 2013, computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional details regarding the assumptions underlying the value of these awards. Effective as of December 31, 2013, the common shares in our general partner were exchanged for common units in our predecessor.

(4) Amounts reflect (i) short-term incentive bonus awards earned by Messrs. Carter, Carroll and Dorn in 2013 and (ii) performance-based cash incentive awards under the BSMC 2012 Executive Incentive Plan (the "EIP") earned by each NEO in 2013. Please see "Narrative Disclosure to the Summary Compensation Table—Short-Term Incentive Bonuses" for additional details regarding the short-term incentive bonus awards earned in 2013. Please see "Narrative Disclosure to the Summary Compensation Table—Long-Term Incentive Awards" for additional details regarding the performance-based cash incentive awards under the EIP earned in 2013.

(5) The amounts included in "All Other Compensation" reflect (i) for Mr. Carter: sporting event tickets of $12,305 that we paid on his behalf as well as matching contributions equal to $12,750 that were made to the 401(k) Plan on his behalf; (ii) for Mr. Carroll: matching contributions equal to $12,750 that were made to the 401(k) Plan on his behalf; and (iii) for Ms. Vanderhider, a severance payment equal to $2,408,000 and matching contributions equal to $4,781 that were made to the 401(k) Plan on her behalf.

Narrative Disclosure to the Summary Compensation Table

For fiscal 2013, the principal elements of compensation provided to our Named Executive Officers were base salaries, short-term incentive bonuses, long-term incentive awards and retirement, health, welfare and additional benefits.

Base Salary

Base salaries are generally set at levels deemed necessary to attract and retain individuals with superior talent commensurate with their relative expertise and experience.

Short-Term Incentive Bonuses

The short-term incentive bonus ("STI Bonus") opportunity is based upon our pay-for-performance philosophy. The STI Bonus provides our Named Executive Officers with an incentive in the form of an annual cash bonus to achieve our overall business goals. The STI Bonuses for fiscal 2013 were equal to the product of each Named Executive Officer's (i) target bonus and (ii) our EBITDA achievement factor for 2013 as reflected below.

Name	Target Bonus Value	EBITDA Achievement Ratio	Actual Bonus Earned
Thomas L. Carter, Jr.	$ 780,000	1.0152596(2)	$ 791,902
Marc Carroll	$ 375,000	1.0508654(3)	$ 394,075
Holbrook F. Dorn	$ 325,000	1.0508654(3)	$ 341,531
Hallie A. Vanderhider(1)	—	—	—

(1) Ms. Vanderhider's employment terminated on May 15, 2013 and, therefore, she did not earn a STI Bonus for 2013.

(2) For purposes of calculating Mr. Carter's 2013 STI Bonus, the EBITDA achievement ratio was calculated as the ratio of our contract EBITDA for 2013 to our budgeted contract EBITDA for 2013. For this purpose, (a) our contract EBITDA for 2013 was calculated as the sum of our (i) net income, (ii) interest expense, (iii) income tax expense, (iv) depreciation, depletion or amortization expense, (v) targeted compensation associated with grants or issuances of equity interests (including carried interests in real property) to employees or members of our board or associated with our incentive or retention plans or agreements (whether cash or equity) and (vi) dry hole expense, as determined in accordance with United States general accepted accounting principles, consistently applied and (b) our budgeted contract EBITDA for 2013 was the contract EBITDA amount projected in the annual budget approved by our board.

(3) For purposes of calculating Messrs. Carroll's and Dorn's 2013 STI Bonuses, the EBITDA achievement ratio was calculated as the ratio of our actual EBITDA for 2013 to our budgeted EBITDA for 2013, as adjusted by an adjustment factor that accelerates the effect of under- or over-achievement such that an EBITDA achievement ratio of 1.3 or more results in a 200% adjustment factor and an EBITDA achievement ratio of 0.7 or less results in a 0% adjustment factor, with linear interpolation between such thresholds. For this purpose, (a) our actual EBITDA for 2013 was calculated as the sum of items (i) through (vi) in footnote 2 above and (b) our budgeted EBITDA for 2013 was the EBITDA amount projected in the annual budget approved by our board.

Long-Term Incentive Awards

In fiscal 2013, each of our Named Executive Officers (other than Ms. Vanderhider) was granted a target incentive award. 50% of each target incentive award consists of a performance-based cash incentive award under the EIP. The performance-based cash incentive awards "cliff" vest at the end of a three-year performance period so long as the NEO remains continuously employed by our general partner or one of its subsidiaries through such date, subject to certain exceptions discussed below under "Additional Narrative Disclosure—Potential Payments

Upon Termination or a Change in Control—2012 Executive Incentive Plan and Restricted Unit Award Agreements.” However, the performance-based cash awards granted in 2012 are subject to three-year graded vesting based on the continued employment requirement (and the applicable exceptions) described above. The ultimate amount paid in respect of each cash incentive award is determined based on the achievement of certain reserve and production targets established by the compensation committee of our board.

The remaining 50% of each target incentive award consisted of common units in our predecessor and common shares in our general partner granted pursuant to Restricted Unit Award Agreements entered into with each NEO. One-third of the units subject to such awards vest ratably on January 1 of each of the three years following the first day of the performance period so long as the NEO remains continuously employed by our general partner or one of its subsidiaries through such date, subject to certain exceptions discussed below under “Additional Narrative Disclosure—Potential Payments Upon Termination or a Change in Control—2012 Executive Incentive Plan and Restricted Unit Award Agreements.” Within 30 days of each vesting date, each NEO may request that we repurchase up to 50% of the units that vest on such date in exchange for a cash payment equal to the then-current fair market value of such units, but we are not under any obligation to accept any such proposed repurchase.

Employment Agreement with Mr. Carter

Mr. Carter entered into an employment agreement with our predecessor in 2008, which was subsequently amended in 2014. The term of the agreement automatically renews annually for successive 12-month periods on March 31 of each year unless either party provides written notice of non-renewal. Under the agreement, Mr. Carter is entitled to an annualized base salary and is eligible for short-term annual bonuses based on the performance measures described above. As discussed below under “Additional Narrative Disclosure—Potential Payments Upon Termination or a Change in Control—Mr. Carter’s Employment Agreement,” the employment agreement also provides for certain severance payments in the event Mr. Carter’s employment is terminated under certain circumstances.

Outstanding Equity Awards at 2013 Fiscal Year-End

The following table reflects information regarding outstanding unvested common units in BSMC held by our Named Executive Officers as of December 31, 2013. In connection with this offering and after the reverse unit split of BSMC’s common units, the common units in BSMC will be exchanged for our common units on an equivalent value basis.

	Unit Awards	
Name	**Number of Units that Have Not Vested(2)**	**Market Value of Units that Have Not Vested(6)**
Thomas L. Carter, Jr.	2,423,237(3)	$ 4,073,039.85
Marc Carroll	1,030,216(4)	$ 1,731,613.88
Holbrook F. Dorn	859,422(5)	$ 1,444,538.88
Hallie A. Vanderhider(1)	—	—

(1) Ms. Vanderhider surrendered all of her unvested equity awards to our predecessor in connection with the termination of her employment.

(2) The applicable equity awards that are disclosed in this Outstanding Equity Awards at 2013 Fiscal Year-End table are common units in our predecessor. Although the awards originally consisted of common units in our predecessor and common shares in our general partner, effective as of December 31, 2013, the common shares in our general partner were exchanged for common units in our predecessor.

(3) 963,180 of these units vested on January 1, 2014. 963,179 of the remaining units will become vested on January 1, 2015 and 496,878 units will become vested on January 1, 2016, in each case, so long as Mr. Carter remains employed by our general partner or one of its affiliates on such dates.

(4) 423,606 of these units vested on January 1, 2014. 384,680 of the remaining units will become vested on January 1, 2015 and 221,930 units will become vested on January 1, 2016, in each case, so long as Mr. Carroll remains employed by our general partner or one of its affiliates on such dates.
(5) 351,447 of these units vested on January 1, 2014. 315,635 of the remaining units will become vested on January 1, 2015 and 192,340 units will become vested on January 1, 2016, in each case, so long as Mr. Dorn remains employed by our general partner or one of its affiliates on such dates.
(6) Reflects the value of the common units in our predecessor as of December 31, 2013, computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional details regarding the assumptions underlying the value of these awards.

Additional Narrative Disclosure

Retirement Benefits

We have not maintained, and do not currently maintain, a defined benefit pension plan or a nonqualified deferred compensation plan providing for retirement benefits. Our Named Executive Officers currently participate in the 401(k) Plan, which permits all eligible employees, including the Named Executive Officers, to make voluntary pre-tax contributions to the plan. In addition, we are permitted to make discretionary matching contributions under the plan. Matching contributions are subject to a graded vesting schedule, with 33% vested after one year, 66% vested after two years, and 100% vested after the initial three years of employment with us. Following three years of employment, future company matching contributions vest immediately. All contributions under the plan are subject to certain annual dollar limitations, which are periodically adjusted for changes in the cost of living.

Potential Payments Upon Termination or a Change in Control.

Mr. Carter's Employment Agreement

Under Mr. Carter's employment agreement, if his employment is terminated by our predecessor without "cause," then so long as Mr. Carter executes a release in a form satisfactory to us within 10 days following such termination, he will receive a lump sum cash severance payment within 60 days following the date of such termination equal to the sum of (1) a pro-rated portion of his target STI Bonus for the year in which such termination occurs (determined without regard to actual performance) and (2) the greater of (A) the sum of (i) any unpaid STI Bonus for the year prior to the year in which such termination occurs and (ii) his then-current base salary and target STI Bonus payable for the remainder of the term of the agreement or (B) the sum of his then-current annualized base salary and target STI Bonus.

In addition, upon Mr. Carter's resignation for "good reason" or a termination of his employment by us without cause following a "change in control," so long as Mr. Carter executes a release in a form satisfactory to us within 10 days following such termination, he will receive a lump sum cash severance payment within 60 days following the date of such termination equal to the sum of (1) a pro-rated portion of his target STI Bonus for the year in which such termination occurs (determined without regard to actual performance) and (2) the greater of (A) the sum of (i) any unpaid STI Bonus for the year prior to the year in which such termination occurs and (ii) his then-current base salary and target STI Bonus payable for the remainder of the term of the agreement or (B) two times the sum of his then-current annualized base salary and target STI Bonus.

For purposes of Mr. Carter's employment agreement:

- "Cause" means Mr. Carter (i) has failed or refused to perform or observe any material term or provision of the agreement (including voluntarily terminating his employment) or to materially follow and satisfactorily perform (in our reasonable discretion) any lawful directions of the board; (ii) has been indicted for or convicted of, or has pleaded guilty or nolo contendere to a charge that he committed, a felony or other crime of moral turpitude; (iii) has perpetrated an act of fraud or dishonesty against or involving, or theft of our property; (iv) has violated any applicable federal, state or local law or regulation and, as a result of such violation, has become, or has caused us to become the subject of any legal action or administrative proceeding or a suspension of any right or privilege; or (v) has committed any act that causes, or knowingly or recklessly fails to take reasonable and appropriate action to prevent, any material injury to our financial condition or business reputation.

- "Good Reason" means at any time subsequent to a change of control or the first public equity offering of partnership interests or other equity securities of our predecessor, our general partner or any controlled subsidiary thereof or successor thereto registered under the Securities Act, we assign to Mr. Carter any duties materially inconsistent with his positions, duties, responsibilities and status with us immediately prior to such change of control or public equity offering or we change Mr. Carter's reporting responsibilities, titles or offices as in effect immediately prior to such change of control or public equity offering.
- "Change of Control" means (i) the transfer of beneficial ownership of a majority of the outstanding units of our predecessor or a majority of the outstanding units of our general partner to any person or entity, except that if beneficial ownership would be deemed to occur merely upon the execution of voting agreements to support a merger, consolidation or other business combination transaction to be consummated in the future, then the board may in its sole discretion determine that the date of such Change of Control shall instead be the date of such consummation; (ii) the partners of our predecessor or the members of our general partner prior to any merger, consolidation or other business combination transaction do not continue to own at least 50% of the surviving entity following such merger, consolidation or other business combination transaction; (iii) other than in the ordinary course of business, our predecessor sells, leases or exchanges all or substantially all of its assets and its controlled subsidiaries, taken as a whole, to any other person or entity (other than a direct or indirect controlled subsidiary of our predecessor); (iv) our predecessor is materially or completely liquidated; (v) on or after an initial public offering, any person or entity becomes the beneficial owner, directly or indirectly, of 30% or more of the units, shares or other equity securities of our predecessor, our general partner or any such subsidiary or successor; or (vi) during any consecutive two-year period, individuals who constituted the board (together with any new managers whose election by the board or whose nomination for election by our general partner was approved by a vote of at least three quarters of the managers still in office who were either managers at the beginning of such period or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority of the board.

Mr. Carter's employment agreement also contains certain restrictive covenants pursuant to which he has recognized certain confidentiality covenants as well as a covenant not to solicit any of our employees or any independent contractor working in our land administration department during the term of the agreement and for a period of two years thereafter.

2012 Executive Incentive Plan and Restricted Unit Award Agreements

Under the EIP, if a NEO's employment terminates due to his death or "disability" or his employment is involuntarily terminated for any other reason other than cause (or, if the NEO has an employment agreement, due to the NEO's resignation for good reason), the NEO (or the NEO's estate, as applicable) will be entitled to receive a pro-rated portion of each cash incentive award for each performance period that includes the NEO's termination date. In addition, pursuant to the Restricted Unit Award Agreements, if a NEO's employment terminates due to his death or "disability" or his employment is involuntarily terminated for any other reason other than cause, a pro-rated portion of the NEO's unvested common units in our predecessor and common units in our general partner will become vested as of such termination. For purposes of the EIP and the Restricted Unit Award Agreements, "cause" and "good reason" generally have the same meanings as described above with respect to Mr. Carter's employment agreement and "disability" means a mental or physical condition resulting from an injury or illness that renders the NEO incapable of performing the essential functions of the NEO's position with reasonable accommodations for 90 days out of any 120-day period.

Long-Term Incentive Plan

Prior to the completion of this offering, we expect our general partner to adopt the Black Stone Minerals, L.P. Long-Term Incentive Plan, or the LTIP, pursuant to which directors, officers (including the named executive officers), certain employees and certain consultants of our general partner and its affiliates will be eligible to receive awards with respect to our common units. The description of the LTIP set forth below is a summary of the material anticipated features of the LTIP. This summary, however, does not purport to be a complete description of all of the provisions of the LTIP and is qualified in its entirety by reference to the LTIP, the form of which will be filed as an exhibit to this registration statement.

The LTIP will provide for the grant, from time to time, at the discretion of the board of directors of our general partner, of unit options, unit appreciation rights, restricted units, phantom units, unit awards, distribution equivalent rights ("DERs") or other unit-based awards. Subject to adjustment in the event of certain transactions or changes in capitalization, an aggregate of   common units may be delivered pursuant to awards under the LTIP. Units subject to awards that are forfeited, cancelled, exercised, paid or otherwise terminated without the delivery of units will be available for delivery pursuant to other awards under the LTIP. The LTIP will be administered by the board of directors of our general partner or a committee thereof, either of which we refer to herein as the "committee." The LTIP will be designed to promote our interests, as well as the interests of our unitholders, by rewarding the directors, officers, employees and consultants of our general partner and its affiliates for superior performance, as well as by strengthening our general partner's and its affiliates' abilities to attract, retain and motivate individuals who are essential for our growth and profitability.

Unit Options and Unit Appreciation Rights

The LTIP will permit the grant of unit options and unit appreciation rights covering common units. Unit options represent the right to purchase a number of common units at a specified exercise price. Unit appreciation rights represent the right to receive the appreciation in the value of a number of common units as of the exercise date over a specified exercise price, either in cash or in common units, as determined in the discretion of the committee. Unit options and unit appreciation rights may be granted to such eligible individuals and with such terms as the committee may determine, consistent with the terms of the LTIP; however, the exercise price of a unit option or unit appreciation right generally must be equal to or greater than the fair market value of a common unit on the date of grant.

Restricted Units and Phantom Units

A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the participant holds a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the participant to receive a common unit (or such greater or lesser number of common units as may be provided pursuant to the applicable award agreement) upon the vesting of the phantom unit (or on a deferred basis upon specified future dates or events) or, in the discretion of the committee, cash equal to the fair market value of a common unit (or such greater or lesser number of common units). The committee may make grants of restricted and phantom units under the LTIP that contain such terms, consistent with the LTIP, as the committee may determine are appropriate, including the period over which restricted or phantom units will vest. The committee may, in its discretion, base vesting on the participant's completion of a period of service or upon the achievement of specified performance criteria or as otherwise set forth in an award agreement. Distributions made by us with respect to awards of restricted units may be subject to the same vesting requirements as the restricted units. The committee, in its discretion, may also grant tandem DERs with respect to phantom units. DERs are described in more detail below.

Unit Awards

A unit award is an award of common units that are fully vested upon grant and are not subject to forfeiture. Unit awards may be paid in addition to, or in lieu of, cash or other compensation that would otherwise be payable to a participant. A unit award may be wholly discretionary in amount or it may be paid with respect to a bonus or other incentive compensation award, the amount of which is determined based on the achievement of performance criteria or other factors.

Distribution Equivalent Rights

The committee is authorized to grant DERs either in tandem with an award or as a separate award. DERs are contingent rights to receive an amount in cash, common units, restricted units, phantom units or any combination thereof, as determined by the committee in its discretion, equal to the cash distributions made on our common units during the period in which such award remains outstanding. The terms and conditions applicable to DERs will be determined by the committee and set forth in an award agreement.

Other Unit-Based Awards

The LTIP will also permit the grant of “other unit-based awards,” which are awards that, in whole or in part, are valued or based on or related to the value of a common unit. The vesting of an other unit-based award may be based on a participant’s continued service, the achievement of specified performance criteria or other measures. On vesting (or on a deferred basis upon specified future dates or events), an other unit-based award may be paid in cash and/or in units, as determined by the committee.

Source of Common Units; Cost; Proceeds

Common units to be delivered with respect to awards under the LTIP may consist, in whole or in part, of common units acquired by us or our general partner in the open market, common units already owned by our general partner or us, common units acquired by our general partner directly from us, one of our affiliates or any other person, new common units otherwise issuable by us or any combination of the foregoing, as determined by the committee in its discretion. With respect to awards made to directors, officers, employees and consultants of our general partner and its affiliates, our general partner will be entitled to reimbursement by us for the cost incurred in acquiring such common units or, with respect to unit options, for the difference between the cost it incurs in acquiring these common units and the proceeds it receives from a participant at the time of the participant’s exercise of an option. Thus, we will bear the cost of all awards under the LTIP. If we issue new common units with respect to these awards, the total number of common units outstanding will increase, and our general partner will remit the proceeds it receives from a participant, if any, upon exercise of an award to us. With respect to any awards settled in cash by our general partner, our general partner will be entitled to reimbursement by us for the amount of the cash settlement.

Amendment or Termination of Long-Term Incentive Plan

The committee, at its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The LTIP will automatically terminate on the 10th anniversary of the date it is initially adopted by our general partner. The committee also has the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP, provided that no change in any outstanding award may be made that would materially reduce the benefit of a participant without the consent of the affected participant.

Director Compensation

Effective as of the closing of this offering, each non-employee director of the board of directors of our general partner will receive a compensation package that will consist of an annual cash retainer of $. Each non-employee director may receive grants of equity-based awards under the long-term incentive plan we intend to adopt prior to the completion of this offering. Our directors will be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees. Officers or employees of our general partner or its subsidiaries who also serve as directors of our general partner will not receive additional compensation for such service.

Each director will be fully indemnified by us for actions associated with serving as a director to the fullest extent permitted under Delaware law.

[Table of Contents](#)

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table presents information regarding the beneficial ownership of our common units and preferred units following this offering and the other formation transactions by:

- our general partner;
- each of our general partner's directors and named executive officers;
- each unitholder known by us to beneficially hold 5% or more of our common units; and
- all of our general partner's directors and executive officers as a group.

Beneficial ownership is determined under the rules of the SEC and generally includes voting or investment power with respect to securities. Unless otherwise noted, the address for each beneficial owner listed below is 1001 Fannin Street, Suite 2020, Houston, Texas 77002.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Preferred Units Beneficially Owned	Percentage of Preferred Units Beneficially Owned	Percentage of Common and Preferred Units Beneficially Owned
Thomas L. Carter, Jr.		%		%	%
Marc Carroll		%		%	%
Holbrook F. Dorn		%		%	%
		%		%	%
		%		%	%
		%		%	%
All directors and executive officers as a group (persons)		%		%	%

* Less than 1%

FIDUCIARY DUTIES

The Delaware Revised Uniform Limited Partnership Act, which we refer to as the Delaware Act, provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict, or eliminate the fiduciary duties otherwise owed by the general partner and the directors and executive officers of the general partner to the partnership and its partners. Our partnership agreement contains provisions that eliminate the fiduciary duties to which our general partner and the directors and executive officers of our general partner would otherwise be held by state fiduciary duty law and imposes contractual standards that our general partner and its directors and executive officers must follow. Our partnership agreement also specifically restricts the situations in which remedies may be available to our unitholders for actions taken that might constitute breaches of duty under applicable Delaware law and breaches of the contractual obligations in our partnership agreement.

When our general partner and the directors and executive officers of our general partner act, it and they must act in “good faith,” meaning it and they must not act in a manner that it and they subjectively believe is adverse to our interest. This duty to act in good faith is the default standard set forth under our partnership agreement, and our general partner and the directors and executive officers of our general partner will not be subject to any higher standard under the partnership agreement or law or equity.

When the directors and executive officers of our general partner cause our general partner to manage and operate our business, the directors and executive officers must cause our general partner to act in a manner consistent with our general partner’s applicable duties and contractual standards. Therefore, where the directors and executive officers of our general partner are causing our general partner to act, the directors and executive officers must cause the general partner to act in good faith, meaning they cannot cause the general partner to take an action that they subjectively believe is adverse to our interest. However, the directors of our general partner may determine, in their sole discretion and free of any duty or obligation (including the obligation to act in good faith), whether to submit a determination to the conflicts committee for review or to seek approval by the unitholders, as described below.

Duties owed by our general partner and the directors and executive officers of our general partner to the partnership and to the unitholders are prescribed by law and in our partnership agreement. The Delaware Act provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict, or eliminate the fiduciary duties that otherwise may be owed by the general partner and the directors and executive officers of our general partner to the partnership and its partners.

Our partnership agreement contains various provisions eliminating the fiduciary duties that might otherwise be owed by our general partner and the directors and executive officers of our general partner and imposing contractual standards that our general partner and its directors and executive officers must follow. We have adopted these provisions to allow our general partner and its directors and executive officers to manage and operate our business with greater flexibility and to subject the actions and determinations of our general partner and its directors and executive officers to lesser legal or judicial scrutiny than would be the case if state law fiduciary standards were applicable. Without these modifications, our general partner’s and the directors’ and officers’ of our general partner ability to make decisions—and, in particular, decisions involving conflicts of interest—may be restricted. The modifications to the fiduciary standards benefit our general partner and the directors and executive officers of our general partner by providing greater flexibility and enabling them to take into consideration all factors and interests of various parties while still imposing a duty to manage our partnership in good faith. These modifications also strengthen the ability of our general partner to attract and retain experienced and capable directors and executive officers.

These modifications may represent a detriment to our public unitholders because they restrict the remedies available to our public unitholders for actions that, without those limitations, might constitute breaches of fiduciary duty, as described below.

The following is a summary of:

- the default fiduciary duties under Delaware law;
- the contractual standards contained in our partnership agreement that replace the default fiduciary duties; and
- certain rights and remedies of limited partners contained in the Delaware Act.

Default state law fiduciary duty standards	Fiduciary duties are generally considered to include a duty of care and a duty of loyalty. The duty of care, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to act and make decisions in an informed and deliberate manner after availing itself of all reasonably available material information. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally require a general partner to make decisions based on the best interests of the partnership and its partners, and not for personal or other reasons. A general partner would generally satisfy the duty of loyalty when it is in a position to base its decision on the merits of the issue rather than being governed by extraneous considerations or influences. In the absence of a provision in a partnership agreement providing otherwise, where a general partner has a material conflict of interest with the partnership and/or the partners with respect to a potential transaction or determination, the duty of loyalty would generally require that any such action taken or determination made be entirely fair to the partnership and the partners and the general partner would typically have the burden of proving the action or transaction is entirely fair.
Partnership agreement modified standards	Our partnership agreement contains provisions that eliminate state law fiduciary duties and replace these duties with a contractually defined standard of “good faith.” For example, our partnership agreement provides that when our general partner is acting it must act in “good faith,” meaning that it believes its actions or omissions are not adverse to the interests of the partnership, and will not be subject to any other standard. The contractual standards set forth in the partnership agreement replace the obligations to which our general partner would otherwise be held. With respect to matters involving a conflict of interest, our general partner and its directors and officers are permitted in their sole discretion and free of any duty or obligation (including the obligation to act in good faith) to determine whether or not to submit these matters for approval by the conflicts committee of the board of directors of our general partner or our common unitholders. If our general partner or its directors or officers in their sole discretion determines not to submit a conflict of interest transaction for approval either by the conflicts committee or our common unitholders, and instead the board of directors of our general partner approves the resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, the

	general partner and the board, which may include board members affected by the conflict of interest, acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting the proceeding will have the burden of overcoming such presumption and proving that the decision was not in good faith. These standards replace the obligations and presumptions to which our general partner would otherwise be held.
Default State Law rights and remedies of limited partners	The Delaware Act generally provides that a limited partner may institute legal action on behalf of the partnership to recover damages from a person where a general partner has refused to institute the action or where an effort to cause a general partner to do so is not likely to succeed. These actions include actions against a general partner for breach of its duties or of our partnership agreement. In addition, the statutory or case law of some jurisdictions may permit a limited partner to institute legal action on behalf of himself and all other similarly situated limited partners to recover damages from a general partner for violations of its fiduciary duties to the limited partners.
Partnership agreement modified standards	The Delaware Act provides that, unless otherwise provided in a partnership agreement, a partner or other person shall not be liable to a limited partnership or to another partner or to another person that is a party to or is otherwise bound by a partnership agreement for breach of fiduciary duty for the partner's or other person's good faith reliance on the provisions of the partnership agreement. Under our partnership agreement, to the extent that, at law or in equity an indemnitee has duties (including fiduciary duties) and liabilities relating thereto to us or to our partners, our general partner and any other indemnitee acting in connection with our business or affairs shall not be liable to us or to any partner for its reliance on the provisions of our partnership agreement. In addition, our partnership agreement provides that our general partner and its directors and officers will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in willful misconduct or fraud or, with respect to any criminal conduct, with the knowledge that its conduct was unlawful.

By purchasing our common units, each common unitholder automatically agrees to be bound by the provisions in our partnership agreement, including the provisions discussed above. This is in accordance with the policy of the Delaware Act favoring the principle of freedom of contract and the enforceability of partnership agreements. The failure of a limited partner to sign a partnership agreement does not render the partnership agreement unenforceable against that person.

DESCRIPTION OF OUR COMMON UNITS

Our Common Units

The common units offered hereby represent limited partner interests in us. The holders of common units are entitled to participate in partnership distributions and exercise the rights and privileges provided to limited partners holding common units under our partnership agreement. For a description of the relative rights and privileges of holders of our common units to partnership distributions, please read "Cash Distribution Policy and Restrictions on Distributions" and "Description of Our Preferred Units—Distributions." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement" and "Description of Our Preferred Units—Distributions."

Transfer Agent and Registrar

American Stock Transfer & Trust Company, LLC will serve as registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units, except the following, which must be paid by unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes, and other governmental charges;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There is no charge to our unitholders for disbursements of our quarterly cash distributions. We will indemnify the transfer agent, its agents, and each of their stockholders, directors, officers, and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If a successor has not been appointed or has not accepted its appointment within 30 days after notice of the resignation or removal, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when the transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power, and authority to become bound by our partnership agreement;
- automatically agrees to be bound by the terms and conditions of, and is deemed to have executed, our partnership agreement; and
- gives the consents, acknowledgments and waivers contained in our partnership agreement, such as the approval of all transactions and agreements entered into in connection with our formation and this offering.

A transferee will become a substituted limited partner of our partnership for the transferred common units automatically upon the recording of the transfer on our books and records. Our general partner will cause any transfers to be recorded on our books and records from time to time as necessary to accurately reflect the transfers.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Common units are securities and are transferable according to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a limited partner in our partnership for the transferred common units.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Listing

We intend to apply to list our common units on the NYSE under the symbol "BSM."

DESCRIPTION OF OUR PREFERRED UNITS

Our Preferred Units

Our Series A Preferred Units, which we refer to as the "preferred units," are substantially the same as the Series A preferred units issued by our predecessor and represent limited partner interests in us. The holders of preferred units are entitled to participate in partnership distributions and exercise certain other rights and privileges under our partnership agreement. We do not currently expect to issue additional preferred units. For a description of the relative rights and privileges of holders of our preferred units to partnership distributions, please read "Cash Distribution Policy and Restrictions on Distributions" and "Description of Our Preferred Units—Distributions." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement" and "Description of Our Preferred Units."

Distributions

Prior to the liquidation of the partnership, and while any of our preferred units remain outstanding, cash, or other property of the partnership will be distributed to our limited partners in the following order and priority at times and in amounts as the General Partner determines in its sole discretion:

(1) First, 100% to our preferred unitholders (pro rata), until the aggregate Unpaid Preferred Yield of each preferred unit accrued through the last day of the immediately preceding calendar quarter has been reduced to zero; and then

(2) Second, in respect of each calendar year, 100% to our common unitholders pro rata until there has been distributed pursuant to this paragraph an aggregate amount in respect of calendar year equal to 10% of the aggregate Interest Fair Market Value of the outstanding common units as of the first day of each calendar year; and

(3) Finally, 100% to our common unitholders and our preferred unitholders pro rata in accordance with their interests in us, determined on an "as converted" basis.

The terms "Interest Fair Market Value," "Preferred Yield," "Unpaid Preferred Yield" and "Liquidation Preference Amount" have the following meanings:

"Interest Fair Market Value" means, as of any date, the amount which would be received by the holder of a common unit if (a) all of the preferred units and any other convertible securities issued by us were converted into or exchanged for common units, and (b) an amount equal to the fair market value of our assets minus our liabilities (adjusted to reflect any increases in our equity value resulting from the deemed conversion of our preferred units and other convertible securities) were distributed to our partners.

"Preferred Yield" means a yield on the outstanding preferred units equivalent to a 10% per annum interest rate (subject to adjustment following certain events of default by the partnership) on an initial investment of $990, calculated based on a 365-day year and compounded quarterly.

"Unpaid Preferred Yield" means, with respect to each preferred unit and as of any date of determination, an amount equal to the excess, if any, of (a) the cumulative Preferred Yield from the Closing Date through the date established, over (b) the cumulative amount of distributions made as of the date established in respect of the preferred unit.

The general partner will be entitled to establish record dates for the payment of distributions and adopt any other procedures deemed by the general partner to be necessary or appropriate.

In connection with the liquidation of the partnership, cash, or other property will be distributed to the Partners in accordance with capital account balances. The manner in which profits and losses are allocated among the Partners pursuant to the partnership agreement is designed to maintain a capital account balance for each preferred unit equal to the Liquidation Preference Amount so that each preferred unitholder will receive the Liquidation Preference Amount upon our liquidation. In the event the capital account balance with respect to each preferred unit does not equal the Liquidation Preference Amount, the preferred unitholders will receive an amount equal to the Liquidation Preference for each preferred unit held by the preferred unitholder.

"Liquidation Preference Amount" means, with respect to any preferred unit outstanding at the time of the liquidation of the Partnership, an amount equal to the sum of (i) the Unpaid Preferred Yield plus (ii) $990.

Conversion of the Preferred Units

Each preferred unit may be converted, at the option of the holder thereof, at any time, and without the payment of additional consideration, into common units at the then effective conversion rate. The preferred units currently have a conversion rate of 907.3629601 common units per preferred unit, each subject to adjustment as provided herein.

On January 1 of each year from 2015 to 2018, a number of preferred units will automatically be converted into common units at the then effective conversion rate. As a result of these mandatory conversions, all preferred units will have either been redeemed or converted into common Units as of January 1, 2018.

A preferred unitholder who converts its shares, or whose shares are automatically converted, will be entitled to receive the Unpaid Preferred Yield on its shares through the conversion date. We will not issue fractions of common units upon conversion of preferred units. We will pay cash in lieu of each fraction of a common unit otherwise issuable upon a conversion.

The preferred units will cease to be convertible on the day of the first liquidating distribution by the partnership.

Each preferred unit which is surrendered for conversion as provided in our partnership agreement will no longer be deemed outstanding as of the conversion date, and all rights with respect to the preferred unit will terminate, except for the rights of the holder thereof to receive common units in exchange therefor (and any payment in lieu of a fractional common unit and payment of any Unpaid Preferred Yield thereon).

Redemption of the Preferred Units

On December 31 of each year from 2014 through 2017 (each date, a "Scheduled Redemption Date"), each preferred unitholder may, upon written notice, require the partnership to redeem a portion of its preferred units for a cash price per preferred unit equal to the sum of $990 plus the Unpaid Preferred Yield accrued through that date (the aggregate amount, the "Holder Redemption Price"). The partnership will pay to the redeeming preferred unitholder the Holder Redemption Price plus, in the event of a payment after the Scheduled Redemption Date, interest on the Holder Redemption Price at a rate of 10% per annum (subject to adjustment following certain events of default by the Partnership from the Scheduled Redemption Date until the date paid to the redeeming preferred unitholder).

If Thomas L. Carter, Jr. is no longer chief executive officer of the general partner or any successor general partner of the partnership or, or is no longer actively involved in the investment decisions, management, and operations of the partnership (a "Key Man Event"), a preferred unitholder may notify the general partner of its objection ("Key Man Objection Notice"), and each preferred unitholder will have the right to require the partnership to redeem its preferred units for a cash price per preferred unit equal to the Holder Redemption Price; provided that if the general partner disputes the occurrence of a Key Man Event, then an independent third-party arbitrator will determine if a Key Man Event occurred. The general partner will provide the preferred unitholders prompt notice following the final determination of the occurrence of a Key Man Event, and for 60 days after the notice, each preferred unitholder will have the right to send a redemption notice to the general partner. Upon receipt of a redemption notice pursuant to this paragraph, the partnership will redeem one-third of the number of preferred units for which a preferred unitholder requests redemption on December 31 of each of the calendar year in which a redemption notice is received and the two following calendar years; provided that in the event of a change of control or a liquidation occurring prior to redemption of these preferred units in full pursuant to this paragraph, the partnership will redeem 100% of these unredeemed preferred units on the date of consummation of the change of control or the date of the first liquidating distribution, as applicable, at a cash price per preferred unit equal to the Holder Redemption Price. The Unpaid Preferred Yield will continue to accrue at a rate of 10% per annum (subject to adjustment following certain events of default by the partnership) on each outstanding preferred unit until redeemed.

If on any Redemption Date the partnership is unable to redeem any preferred units designated for redemption in the redemption notice for any reason, then the partnership will redeem, pro rata among the preferred unitholders who have given a redemption notice (based on the number of preferred units held by the redeeming preferred unitholders as of the redemption date), as many of the preferred units as may be redeemed, and as soon thereafter as the partnership is able the partnership will redeem such unredeemed preferred units; provided that the partnership will be deemed to be in default if the partnership is unable all of the preferred units designated for redemption in the redemption notice.

In the event that a preferred unitholder gives a redemption notice with respect to any Scheduled Redemption Date, the partnership will have the option to redeem from a preferred unitholder, for a cash price per preferred unit equal to the greater of (i) the Holder Redemption Price, or (ii) the Interest Fair Market Value of the common units into which the preferred units so redeemed are convertible on such Scheduled Redemption Date (the “Partnership Redemption Price”), an additional number of preferred units up to the number of preferred units designated for redemption by the preferred unitholder in such redemption notice; *provided* that the partnership will not exercise the redemption rights pursuant to this paragraph while a default by the partnership is continuing.

In the event of a change of control or anticipated change of control, except with respect to any preferred unit a preferred unitholder elects to convert, the partnership will redeem the preferred units upon the consummation of the change of control.

From and after the redemption of any preferred units in full, all rights of the holders (except the right to receive the redemption payment, plus interest if applicable) will cease, and the preferred units will be deemed to no longer be outstanding for any purpose whatsoever.

Anti-Dilution Provisions

The Conversion Price and the Conversion Rate will be subject to adjustment from time to time in accordance with this “Description of Our Preferred Units.”

If we at any time (i) subdivide our outstanding common units, (ii) make a distribution on our outstanding common units payable in common units, or (iii) combine our outstanding preferred units, the conversion rate and conversion price for the preferred units will be proportionately decreased (with appropriate adjustments to the Conversion Rate in effect immediately prior to the subdivision or distribution). If we at any time (i) combine our outstanding common units, (ii) subdivide our outstanding preferred units, or (iii) make a distribution on our outstanding preferred units payable in preferred units, the conversion price for our preferred units will be proportionately increased (with appropriate adjustments to the conversion rate in effect immediately prior to the combination).

If as a result of any capital reorganization or reclassification of our common units or consolidation or merger of the partnership with another entity, our common unitholders would receive stock, securities, cash, or other property with respect to or in exchange for common units, then the preferred unitholders will have the right to acquire and receive upon conversion of the preferred units, the shares of stock, securities, cash, or other property issuable or payable (as part of the reorganization, reclassification, consolidation, merger, or sale) with respect to or in exchange for the number of outstanding common units that this would have received upon conversion of the preferred units at the applicable conversion rate.

If any event occurs as to which, in the good faith opinion of the general partner, the provisions of this section entitled “Anti-Dilution Provisions” are not strictly applicable or would not fairly protect the rights of the preferred unitholders, then the general partner will make an adjustment, so as to protect these rights.

Voting; Waiver

Except with respect to certain matters requiring the approval of the preferred unitholders, which are set forth in Annex A to our Partnership Agreement, at each meeting of the partners (or pursuant to any action by written consent), with respect to any and all matters presented to the partners for their action or consideration, each preferred unitholder will be entitled to vote as a single class with the common units on an “as-converted basis,” meaning that each preferred unit has a number of votes equal to the number of common units into which the preferred unit is convertible at the time of such vote or consent.

Co-Investment Right

In the event a property acquisition is being considered by the partnership or its subsidiaries and the partnership does not, directly or indirectly, acquire the full amount of the property (such excess not acquired by the partnership being the “Qualified Property”), the preferred unitholders will have the right to participate in the acquisition (“Co-Investment Rights”) of such Qualified Property, pro rata in proportion to their respective ownership of preferred units, on the economic terms and conditions determined by the general partner. If a preferred unitholder does not exercise in full its Co-Investment Right, all exercising preferred unitholders may elect to purchase (the “Additional Purchase Right”) any interest in the Qualified Property not to be acquired pursuant to the exercise of the Co-Investment Rights. If any preferred unitholder declines to exercise its Additional Purchase Right, the preferred unitholders exercising their Additional Purchase Rights may acquire the remaining interest in the Qualified Property. The Co-Investment Rights of the preferred unitholders will terminate as of December 31, 2014.

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. The form of our partnership agreement is included in this prospectus as Appendix A. We will provide investors and prospective investors with a copy of our partnership agreement upon request at no charge.

We summarize the following provisions of our partnership agreement elsewhere in this prospectus:

- with regard to the duties of our general partner, please read "Fiduciary Duties";
- with regard to the transfer of common units, please read "Description of Our Common Units—Transfer of Common Units"; and
- with regard to allocations of taxable income and taxable loss, please read "Material U.S. Federal Income Tax Consequences."

Organization and Duration

We were organized in September 2014 and will have a perpetual existence unless terminated pursuant to the terms of our partnership agreement.

Purpose

Our purpose, as set forth in our partnership agreement, is to engage in any business activity that is approved by our general partner and that lawfully may be conducted by a limited partnership organized under Delaware law; provided that our general partner shall not cause us to take any action that the general partner determines would be reasonably likely to cause us to be treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes.

Our general partner is generally authorized to perform all acts it determines to be necessary or appropriate to carry out our purposes and to conduct our business.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Adjustments to Capital Accounts Upon Issuance of Additional Common Units

We will make adjustments to capital accounts upon the issuance of additional common units. In doing so, we will generally allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to our unitholders prior to an issuance on a pro rata basis, so that after such issuance, the capital account balances attributable to all common units are equal.

Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that call for the approval of a "unit majority" require the approval of a majority of the outstanding common units.

In voting their common units, our directors will have no duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interests of us or the limited partners. The holders of a majority of the common units represented in person or by proxy shall constitute a quorum at a meeting of such common unitholders, unless any such action requires approval by holders of a greater percentage of the units in which case the quorum shall be the greater percentage.

The following is a summary of the vote requirements specified for certain matters under our partnership agreement.

Election of directors of our general partner	Our limited partners holding common units and preferred units will vote together as a single class for the election of directors to the board of directors of our general partner. The limited partners authorized to vote will elect, by a plurality of the votes cast at such meeting, persons to serve as directors of our general partner who are nominated in accordance with the provisions of our partnership agreement. Limited Partners will be entitled to cumulate their votes for purposes of electing directors. Please read "—Nomination of Directors."
Issuance of additional units (including units senior to the common units)	No approval right by limited partners holding common units, including units that are senior to the common units. However, our partnership agreement does not authorize us to issue securities having preferences or rights with priority over or on a parity with the preferred units with respect to rights to share in distributions, redemption obligations or redemption rights.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of any limited partners. Other amendments generally require the approval of a majority of our limited partners holding common units and preferred units. Please read "—Amendment of the Partnership Agreement."
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances. Please read "—Merger, Consolidation, Conversion, Sale or Other Disposition of Assets."
Dissolution of our partnership	Unit majority Please read "—Dissolution."
Continuation of our business upon dissolution	Unit majority. Please read "—Dissolution."
Withdrawal of our general partner	No voluntary withdrawal right. Please read "—Withdrawal or Removal of Our General Partner; Transfer of General Partner Interest."
Transfer of our general partner interest	No transfer right without the consent of a unit majority. Please read "—Withdrawal or Removal of Our General Partner; Transfer of General Partner Interest."

If any person or group other than our directors and their affiliates, a limited partner in our predecessor who beneficially owned 15% or more of our common units as of the date of our initial public offering, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, acquires beneficial ownership of 15% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply to any person or group that acquires the units from the limited partners in our predecessor or its affiliates and any transferees of that person or group approved by the board of directors of our general partner or to any person or group who acquires the units with the specific prior approval of the board of directors of our general partner.

Meetings; Voting

An annual meeting of the limited partners holding common units and preferred units for the election of directors to the board of directors of our general partner will be held at a date and time as may be fixed from time to time by our general partner. Notice of the annual meeting will be given not less than 10 days nor more than 60 days prior to the date of the meeting.

The limited partners holding common units and preferred units will vote together as a single class for the election of directors. The limited partners authorized to vote will elect by a plurality of the votes cast at a meeting persons to serve as directors on the board of directors of our general partner who are nominated in accordance with the provisions of our partnership agreement. The exercise by a limited partner of the right to elect the directors and any other rights afforded to a limited partner under our partnership agreement will be in the limited partner's capacity as a limited partner of the partnership and are not intended to cause a limited partner to be deemed to be taking part in the management and control of the business and affairs of the partnership.

Each limited partner entitled to vote at an election for the board of directors will be entitled to cumulate his or her vote and give one candidate, or divide among any number of candidates, a number of votes equal to the product of (x) the number of common units held by the limited partner, multiplied by (y) the number of directors to be elected at the meeting.

Additional limited partner interests having special voting rights could be issued. However, our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to change management without the support of the board of directors of our general partner. If at any time any person or group, other than (a) a person who is one of our directors, his or her affiliates, or a limited partner in our predecessor with beneficial ownership of 15% or more of our common units as of the date of our initial public offering, (b) a transferee of any of the persons described in the preceding clause (a) with the prior approval of the board of directors of our General Partner, or (c) a person or group that acquires units with the prior approval of the board of directors of our general partner, acquires, in the aggregate, beneficial ownership of 15% or more of any class of units then outstanding, that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes, as contemplated in our partnership agreement.

In addition, solely with respect to the election of directors, our partnership agreement provides that our general partner and the partnership will not be entitled to vote their units, if any, and the foregoing units will not be counted when calculating the required votes for a matter and will not be deemed to be outstanding for purposes of determining a quorum for a meeting. These units will not be treated as a separate class of Partnership securities for purposes of our partnership agreement.

Except as described above, unitholders on the record date will be entitled to notice of, and to vote at, meetings of our limited partners, and to act upon matters for which approvals may be solicited. Units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise. Units that are owned by Non-Eligible Holders will be voted by our general partner and our general partner will distribute the votes on those units in the same ratios as the votes of partners on other units are cast.

Any action that is required or permitted to be taken by our unitholders may be taken either at a meeting of the unitholders or, if authorized by our general partner, without a meeting if consents in writing describing the action so taken are signed by holders of the number of units as would be necessary to authorize or take that action at a meeting. Special meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting was called (including outstanding units deemed owned by the general partner), represented in person or by proxy, will constitute a quorum unless otherwise provided in our partnership agreement in connection with the election of directors to the board of directors of our general partner or unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Any notice, demand, request, report, or proxy material required or permitted to be given or made to record holders of units under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Nomination of Directors

Nominations of persons for election to the board of directors of our general partner may be made at an annual meeting of the limited partners only (a) pursuant to our general partner's notice of meeting (or any supplement thereto), (b) by or at the direction of the board of directors or any committee thereof, or (c) by any limited partner or group of limited partners who (1) was a record holder at the time the notice provided for in our partnership agreement is delivered to our general partner, (2) is entitled to vote at the meeting, (3) complies with the notice procedures set forth in our partnership agreement, and (4) either individually or as a group hold units representing at least 10% of the outstanding units (measured on a fully diluted basis) both at the time of giving notice of such nomination and at the meeting.

For any nominations brought before an annual meeting by a limited partner, the limited partner must give timely notice thereof in writing to our general partner. The notice must contain certain information as described in our partnership agreement. To be timely, a limited partner's notice must be delivered to our general partner not later than the close of business on the 90th day, nor earlier than the close of business on the 120th day, prior to the first anniversary of the preceding year's annual meeting (provided, however, that in the event that the date of the annual meeting is more than 30 days before or more than 70 days after the anniversary date, notice by the limited partner must be so delivered not earlier than the close of business on the 120th day prior to the annual meeting and not later than the close of business on the later of the 90th day prior to the annual meeting or the 10th day following the day on which public announcement of the date of the meeting is first made by the partnership or our general partner). The public announcement of an adjournment or postponement of an annual meeting will not commence a new time period (or extend any time period) for the giving of a limited partner's notice as described above.

In the event that the number of directors to be elected to the board of directors of our general partner is increased effective at the annual meeting and there is no public announcement by the partnership or our general partner naming the nominees for the additional directorships at least 100 days prior to the first anniversary of the preceding year's annual meeting, a limited partner's notice will also be considered timely, but only with respect to nominees for the additional directorships, if it shall be delivered to our general partner not later than the close of business on the 10th day following the day on which a public announcement is first made by the partnership or our general partner.

Nominations of persons for election to the board of directors also may be made at a special meeting of limited partners at which directors are to be elected in accordance with the provisions of our partnership agreement.

Only persons who are nominated in accordance with the procedures set forth in our partnership agreement will be eligible to be elected at an annual or special meeting of limited partners to serve as directors. Notwithstanding the foregoing, unless otherwise required by law, if the limited partner (or a qualified representative of the limited partner) does not appear at the annual or special meeting of limited partners to present a nomination, the nomination shall be disregarded notwithstanding that proxies in respect of a vote may have been received by our general partner or the partnership.

In addition to the provisions described above and in our partnership agreement, a limited partner must also comply with all applicable requirements of the Exchange Act and the rules and regulations thereunder; provided, however, that any references in our partnership agreement to the Exchange Act or the rules promulgated thereunder are not intended to and do not limit any requirements applicable to nominations pursuant to our partnership agreement, and compliance with our partnership agreement is the exclusive means for a limited partner to make nominations.

Applicable Law; Forum, Venue, and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions, or proceedings:

- arising out of or relating in any way to the partnership agreement (including any claims, suits, or actions to interpret, apply, or enforce the provisions of the partnership agreement or the duties, obligations, or liabilities among limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a duty owed by any director, officer, or other employee of us or our general partner, or owed by our general partner, to us, or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), regardless of whether the claims, suits, actions, or proceedings sound in contract, tort, fraud, or otherwise, are based on common law, statutory, equitable, legal, or other grounds, or are derivative or direct claims and irrevocably waives the right to trial by jury.

If any person brings any of the aforementioned claims, suits, actions, or proceedings and the person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then the person shall be obligated to reimburse us and our affiliates for all fees, costs, and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action, or proceeding.

By purchasing a common unit, a limited partner is irrevocably consenting to these limitations and provisions regarding claims, suits, actions, or proceedings and submitting to the exclusive jurisdiction of the Court of Chancery of the State of Delaware (or such other court) in connection with any such claims, suits, actions, or proceedings.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that he otherwise acts in conformity with the provisions of the partnership agreement, his liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital he is obligated to contribute to us for his common units plus his share of any undistributed profits and assets. However, if it were determined that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, prior to the dissolution of a limited partnership, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years. Following the dissolution of a limited partnership, the Delaware Act generally requires a limited partnership to satisfy (or make reasonable provision to satisfy) liabilities of the limited partnership prior to making distributions to partners.

Following the completion of this offering, we may have subsidiaries that conduct business in other states or countries in the future. Maintenance of our limited liability as owner of our operating subsidiaries may require compliance with legal requirements in the jurisdictions in which the operating subsidiaries conduct business, including qualifying our subsidiaries to do business there.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership interest in our subsidiaries or otherwise, it were determined that we were conducting business in any jurisdiction without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Partnership Interests

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders (other than, in certain instances, approval of the holders of our preferred units).

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units we issue will be entitled to share equally with the then-existing common unitholders in our distributions. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing common unitholders in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit our subsidiaries from issuing equity interests, which may effectively rank senior to the common units.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or to call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without his consent, unless approved by at least a majority of the type or class of limited partner interests so affected;
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion; or
- amend or modify the rights of our preferred unitholders, create certain new classes of preferred units, or cause the partnership to issue certain redeemable securities without the consent of a supermajority of the preferred unitholders.

The provision of our partnership agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units, voting as a single class (including units owned by our general partner and its affiliates).

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner holding common units to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;
- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor any of our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes (to the extent not already so treated or taxed);
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940 or “plan asset” regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary, appropriate or desirable in connection with the creation, authorization or issuance of additional partnership interests or the right to acquire partnership interests;

- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;
- any amendment that our general partner determines to be necessary, appropriate or desirable for the formation by us of, or our investment in, any corporation, partnership, or other entity, as otherwise permitted by our partnership agreement;
- a change in our fiscal year or taxable year and related changes;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities, or operations at the time of the conversion, merger, or conveyance other than those it receives by way of the conversion, merger, or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement, without the approval of any limited partner holding common units, if our general partner determines that those amendments:

- do not adversely affect the limited partners (including any particular class of partnership interests as compared to other classes of partnership interests) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions, or guidelines contained in any opinion, directive, order, ruling, or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary, appropriate, or desirable to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline, or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;
- are necessary, appropriate, or desirable for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement; or
- are required to effect the intent expressed in this prospectus or the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

Any amendment that our general partner determines adversely affects in any material respect one or more particular classes of limited partners, and is not permitted to be adopted by our general partner without limited partner approval, will require the approval of at least a majority of the class or classes so affected, but no vote will be required by any class or classes of limited partners that our general partner determines are not adversely affected in any material respect. Any such amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any such amendment that would reduce the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any such amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will neither result in a loss of limited liability to the limited partners nor result in our being treated as a taxable entity for federal income tax purposes in connection with any of the amendments. No other amendments to our partnership agreement will become effective without the approval of holders of at least 90% of the outstanding units, voting as a single class, unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

Merger, Consolidation, Conversion, Sale, or Other Disposition of Assets

A merger, consolidation, or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation, or conversion and may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in the best interest of us or the limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to sell, exchange, or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation, or other combination. Our general partner may, however, mortgage, pledge, hypothecate, or grant a security interest in all or substantially all of our assets without majority approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without majority approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction and the partnership interests to be issued do not exceed 20% of our outstanding partnership interests immediately prior to the transaction.

If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger, or conveyance is to effect a mere change in our legal form into another limited liability entity, we have received an opinion of counsel regarding limited liability and tax matters and the governing instruments of the new entity provide the limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters’ rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger, or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Dissolution

We will continue as a limited partnership until dissolved under our partnership agreement. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;
- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;
- the entry of a decree of judicial dissolution of our partnership; or
- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or its withdrawal or removal following the approval and admission of a successor.

Upon a dissolution under the last clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and

- neither our partnership nor any of our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless such dissolution is revoked, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as set forth in our partnership agreement. The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners. Please read "Description of Our Preferred Units—Distributions."

Withdrawal or Removal of Our General Partner; Transfer of General Partner Interest

Our general partner does not have the right to withdraw voluntarily as our general partner, and any such withdrawal would be a breach of our partnership agreement. In addition, our partnership agreement does not permit our general partner, to sell or otherwise transfer its general partner interest in us without the consent of a unit majority.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to change our management. If any person or group, other than the initial limited partners in our predecessor, their transferees, and persons who acquired their units with the prior approval of the board of directors of our general partner, acquires beneficial ownership of 15% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply in certain circumstances. Furthermore, a person or group must own at least 10% of our outstanding units (on a fully diluted basis) to nominate persons for election to our board of directors. Please read "—Meetings; Voting."

Non-Taxpaying Holders; Redemption

To avoid any adverse effect on our ability to operate our assets or generate revenues from our assets, our partnership agreement provides our general partner the power to amend our partnership agreement. If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners (or their owners, to the extent relevant), has, or is reasonably likely to have, a material adverse effect on our ability to operate our assets or generate revenues from our assets, then our general partner may adopt amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the federal income tax status of our limited partners (and their owners, to the extent relevant); and
- permit us to redeem the common units held by any person whose tax status has or is reasonably likely to have a material adverse effect on our ability to operate our assets or generate revenues from our assets or who fails to comply with the procedures instituted by our general partner to obtain proof of a person's federal income tax status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Non-Citizen Assignees; Redemption

If our general partner, with the advice of counsel, determines we are subject to federal, state, or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship, or other related status of any limited partner (or its owners, to the extent relevant), then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the nationality, citizenship, or other related status of our limited partners (or their owners, to the extent relevant); and
- permit us to redeem the common units held by any person whose nationality, citizenship, or other related status creates substantial risk of cancellation or forfeiture of any property or who fails to comply with the procedures instituted by the general partner to obtain proof of the nationality, citizenship, or other related status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Non-Eligible Holders; Redemption

To comply with certain U.S. laws relating to the ownership of interests in oil and gas leases on federal lands, common unit transferees may be required to fill out a properly completed transfer application certifying, and our general partner, acting on our behalf, may at any time require each common unitholder to re-certify that the common unitholder is an Eligible Holder. As used herein, an Eligible Holder means a person or entity qualified to hold an interest in oil and gas leases on federal lands. As of the date hereof, Eligible Holder means: (1) a citizen of the United States; (2) a corporation organized under the laws of the United States or of any state thereof; or (3) an association of United States citizens, such as a partnership or limited liability company, organized under the laws of the United States or of any state thereof, but only if such association does not have any direct or indirect foreign ownership, other than foreign ownership of stock in a parent corporation organized under the laws of the United States or of any state thereof. For the avoidance of doubt, onshore mineral leases, or any direct or indirect interest therein may be acquired and held by aliens only through stock ownership, holding, or control in a corporation organized under the laws of the United States or of any state thereof and only for so long as the alien is not from a country that the United States federal government regards as denying similar privileges to citizens or corporations of the United States. This certification can be changed in any manner our general partner determines is necessary or appropriate to implement its original purpose.

If a common unit transferee or common unitholder, as the case may be:

- fails to furnish a transfer application containing the required certification;
- fails to furnish a re-certification containing the required certification within 30 days after request; or
- provides a false certification;

then, as the case may be, such transfer will, to the fullest extent permitted by law, be void or we will have the right to redeem the units held by the common unitholder. Further, the common units held by the common unitholder may not be entitled to any allocations of income or loss, distributions, or voting rights.

The purchase price will be paid in cash or delivery of a promissory note, as determined by our general partner. Any such promissory note will bear interest at the rate of 8% annually and be payable in three equal annual installments of principal and accrued interest, commencing one year after the redemption date.

For the avoidance of doubt, we will not adopt Eligible Holder requirements regarding those investors who own our preferred units.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Except as described under “—Limited Liability,” the common units will be fully paid, and unitholders will not be required to make additional contributions. For a description of our preferred unitholders’ transfer rights, please read “Description of Our Preferred Units.”

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a manager, managing member, general partner, director, officer, fiduciary, or trustee of our partnership, our subsidiaries, our general partner, any departing general partner or any of their affiliates;
- any person who is or was serving as a manager, managing member, general partner, director, officer, employee, agent, fiduciary, or trustee of another person owing a fiduciary duty to us or our subsidiaries;
- any person who controls our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless our general partner otherwise agrees, it will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner for all direct and indirect expenses it incurs or payments it makes on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner. Our general partner is entitled to determine the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. These books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of our common units, within 105 days after the close of each fiscal year, an annual report containing audited consolidated financial statements and a report on those consolidated financial statements by our independent public accountants. Except for our fourth quarter, we will also furnish or make available summary financial information within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website that we maintain.

We will furnish each record holder with information reasonably required for federal and state tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on their cooperation in supplying us with specific information. Every unitholder will receive information to assist him in determining his federal and state tax liability and in filing his federal and state income tax returns, regardless of whether he supplies us with the necessary information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related (as determined by our general partner) to his interest as a limited partner, upon reasonable written demand stating the purpose of the demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder;
- copies of our partnership agreement, our certificate of limited partnership, related amendments, and powers of attorney under which they have been executed; and
- such other information regarding our affairs as our general partner determines is just and reasonable.

Under our partnership agreement, however, each of our limited partners and other persons who acquire interests in our partnership interests, do not have rights to receive information from us or any of the persons we indemnify as described above under "—Indemnification" for the purpose of determining whether to pursue litigation or assist in pending litigation against us or those indemnified persons relating to our affairs, except pursuant to the applicable rules of discovery relating to the litigation commenced by the person seeking information.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner determines is not in our best interests or that we are required by law or by agreements with third parties to keep confidential. Our partnership agreement limits the rights to information that a limited partner would otherwise have under Delaware law.

UNITS ELIGIBLE FOR FUTURE SALE

Our common units sold in this offering and issued to the limited partners of BSMC in connection with the merger will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units held by an "affiliate" of ours may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate of the issuer to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1% of the total number of the securities outstanding; or
- the average weekly reported trading volume of our common units for the four weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about us. A person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned our common units for at least six months (provided we are in compliance with the current public information requirement), or one year (regardless of whether we are in compliance with the current public information requirement), would be entitled to sell those common units under Rule 144, subject only to the current public information requirement. After beneficially owning Rule 144 restricted units for at least one year, a person who is not deemed to have been an affiliate of ours at any time during the 90 days preceding a sale would be entitled to freely sell those common units without regard to the public information requirements, volume limitations, manner of sale provisions, and notice requirements of Rule 144.

Our partnership agreement provides that we may issue an unlimited number of limited partner interests of any type and at any time without a vote of the unitholders (other than, in certain instances, approval of the holders of our preferred units). Any issuance of additional common units or other limited partner interests would result in a corresponding decrease in the proportionate ownership interest in us represented by, and could adversely affect the cash distributions to and market price of, common units then outstanding. Please read "The Partnership Agreement—Issuance of Additional Partnership Interests."

Under the registration rights agreement that we expect to enter into, certain of our affiliates will have the right to cause us to register under the Securities Act and applicable state securities laws the offer and sale of any units that they hold. Subject to the terms and conditions of the registration rights agreement, these registration rights allow certain of our affiliates or their assignees holding any common units to require registration of any of these units and to include any of these units in a registration by us of other units, including units offered by us or by any unitholder. In connection with any registration of this kind, we will indemnify each unitholder participating in the registration and its officers, directors, and controlling persons from and against any liabilities under the Securities Act or any applicable state securities laws arising from the registration statement or prospectus. We will bear all costs and expenses incidental to any registration, excluding any underwriting discount. Except as described below, certain of our affiliates may sell their units in private transactions at any time, subject to compliance with applicable laws.

The executive officers and directors of our general partner have agreed not to sell any common units they beneficially own for a period of 180 days from the date of this prospectus. Please read "Underwriting" for a description of these lock-up provisions.

Prior to the completion of this offering, we expect to adopt a new long-term incentive plan. If adopted, we intend to file a registration statement on Form S-8 under the Securities Act to register common units issuable under the long-term incentive plan. This registration statement on Form S-8 is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, common units issued under the long-term incentive plan will be eligible for resale in the public market without restriction after the effective date of the Form S-8 registration statement, subject to applicable vesting requirements, Rule 144 limitations applicable to affiliates and the lock-up restrictions described above.

MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES

This section summarizes the material federal income tax consequences that may be relevant to prospective unitholders and is based upon current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury regulations thereunder (the "Treasury Regulations"), and current administrative rulings and court decisions, all of which are subject to change. Changes in these authorities may cause the federal income tax consequences to a prospective unitholder to vary substantially from those described below, possibly on a retroactive basis. Unless the context otherwise requires, references in this section to "we" or "us" are references to Black Stone Minerals, L.P. and its subsidiaries.

Legal conclusions contained in this section, unless otherwise noted, are the opinion of Vinson & Elkins L.L.P. and are based on the accuracy of representations made by us to them for this purpose. However, this section does not address all federal income tax matters that affect us or our unitholders and does not describe the application of the alternative minimum tax that may be applicable to certain unitholders. Furthermore, this section focuses on unitholders who are individual citizens or residents of the United States (for federal income tax purposes), who have the U.S. dollar as their functional currency, who use the calendar year as their taxable year, and who hold units as capital assets (generally, property that is held for investment). This section has limited applicability to corporations, partnerships (including entities treated as partnerships for federal income tax purposes), estates, trusts, non-resident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, non-U.S. persons, IRAs, employee benefit plans, real estate investment trusts, or mutual funds. ***Accordingly, we encourage each unitholder to consult the unitholder's own tax advisor in analyzing the federal, state, local, and non-U.S. tax consequences particular to that unitholder resulting from ownership or disposition of units and potential changes in applicable tax laws.***

We are relying on opinions and advice of Vinson & Elkins L.L.P. with respect to the matters described herein. An opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or a court. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any such contest of the matters described herein may materially and adversely impact the market for units and the prices at which our units trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders because the costs will reduce our cash available for distribution. Furthermore, the tax consequences of an investment in us may be significantly modified by future legislative or administrative changes or court decisions, which may be retroactively applied.

For the reasons described below, Vinson & Elkins L.L.P. has not rendered an opinion with respect to the following federal income tax issues: (1) the treatment of a unitholder whose units are the subject of a securities loan (*e.g.*, a loan to a short seller to cover a short sale of units) (please read "—Tax Consequences of Unit Ownership—Treatment of Securities Loans"); (2) whether our monthly convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read "—Disposition of Units—Allocations Between Transferors and Transferees"); and (3) whether our method for taking into account Section 743 adjustments is sustainable in certain cases (please read "—Tax Consequences of Unit Ownership—Section 754 Election" and "—Uniformity of Units").

Taxation of the Partnership

Partnership Status

We expect to be treated as a partnership for U.S. federal income tax purposes and, therefore, generally will not be liable for entity-level federal income taxes. Instead, as described below, each of our unitholders will take into account its respective share of our items of income, gain, loss, and deduction in computing its federal income tax liability as if the unitholder had earned the income directly, even if we make no cash distributions to the unitholder.

Section 7704 of the Code generally provides that publicly traded partnerships will be treated as corporations for federal income tax purposes. However, if 90% or more of a partnership's gross income for every taxable year it is publicly traded consists of “qualifying income,” the partnership may continue to be treated as a partnership for federal income tax purposes (the “Qualifying Income Exception”). Qualifying income includes income and gains derived from the exploration, production, and marketing of certain natural resources, including crude oil, natural gas, and products thereof, as well as other types of income such as interest (other than from a financial business) and dividends. We estimate that less than % of our current gross income is not qualifying income; however, this estimate could change from time to time.

Based upon factual representations made by us and our general partner, Vinson & Elkins L.L.P. is of the opinion that we will be treated as a partnership and our direct and indirect partnership and limited liability company subsidiaries (other than our general partner) will be disregarded as separate from us or treated as partnerships for federal income tax purposes. The representations made by us and our general partner upon which Vinson & Elkins L.L.P. has relied in rendering its opinion include, without limitation:

(a) Neither we nor any of our partnership or limited liability company subsidiaries (other than our general partner) has elected to be treated as a corporation for federal income tax purposes; and

(b) For each taxable year since and including the year of our initial public offering, more than 90% of our gross income has been and will be income of a character that Vinson & Elkins L.L.P. has opined is “qualifying income” within the meaning of Section 7704(d) of the Code.

We believe that these representations are true and will be true in the future.

If we fail to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require us to make adjustments with respect to our unitholders or pay other amounts), we will be treated as transferring all of our assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which we fail to meet the Qualifying Income Exception, in return for stock in that corporation and then as distributing that stock to our unitholders in liquidation. This deemed contribution and liquidation should not result in the recognition of taxable income by our unitholders or us so long as our liabilities do not exceed the tax basis of our assets. Thereafter, we would be treated as an association taxable as a corporation for federal income tax purposes.

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative or legislative action or judicial interpretation at any time. For example, from time to time, members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the Qualifying Income Exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our units.

If for any reason we are taxable as a corporation in any taxable year, our items of income, gain, loss, and deduction would be taken into account by us in determining the amount of our liability for federal income tax, rather than being passed through to our unitholders. Our taxation as a corporation would materially reduce the cash available for distribution to unitholders and thus would likely substantially reduce the value of our units. Any distribution made to a unitholder at a time we are treated as a corporation would be (i) a taxable dividend to the extent of our current or accumulated earnings and profits, then (ii) a nontaxable return of capital to the extent of the unitholder’s tax basis in its units, and thereafter (iii) taxable capital gain.

The remainder of this discussion is based on the opinion of Vinson & Elkins L.L.P. that we will be treated as a partnership for federal income tax purposes.

Tax Consequences of Unit Ownership

Limited Partner Status

Unitholders who are admitted as limited partners of the partnership, as well as unitholders whose units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of units, will be treated as partners of the partnership for federal income tax purposes. For a discussion related to the risks of losing partner status as a result of securities loans, please read "—Tax Consequences of Unit Ownership—Treatment of Securities Loans." Unitholders who are not treated as partners in us as described above are urged to consult their own tax advisors with respect to the tax consequences applicable to them under their particular circumstances.

Flow-Through of Taxable Income

Subject to the discussion below under "—Entity-Level Collections of Unitholder Taxes" with respect to payments we may be required to make on behalf of our unitholders, we will not pay any federal income tax. Rather, each unitholder will be required to report on its federal income tax return each year its share of our income, gains, losses, and deductions for our taxable year or years ending with or within its taxable year. Consequently, we may allocate income to a unitholder even if that unitholder has not received a cash distribution.

Basis of Units

A unitholder's tax basis in its units initially will be the amount paid for those units increased by the unitholder's initial allocable share of our liabilities. That basis generally will be (i) increased by the unitholder's share of our income and any increases in a unitholder's share of our liabilities, and (ii) decreased, but not below zero, by the amount of all distributions to the unitholder, the unitholder's share of our losses, and any decreases in the unitholder's share of our liabilities. The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all of those interests.

Ratio of Taxable Income to Distributions

We estimate that a purchaser of units in this offering who owns those units from the date of closing of this offering through the record date for distributions for the period ending December 31, , will be allocated, on a cumulative basis, an amount of federal taxable income that will be approximately % of the cash expected to be distributed on those units with respect to that period. These estimates are based upon the assumption that earnings from operations will approximate the amount required to make the anticipated quarterly distributions on all units and other assumptions with respect to capital expenditures, cash flow, net working capital, and anticipated cash distributions. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive, and political uncertainties beyond our control. Further, the estimates are based on current tax law and tax reporting positions that we will adopt and which could be changed or with which the IRS could disagree. Accordingly, we cannot assure that these estimates will prove to be correct, and our counsel has not opined on the accuracy of these estimates. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could affect the value of units. For example, the ratio of taxable income to cash distributions to a purchaser of units in this offering would be higher, and perhaps substantially higher, than our estimate with respect to the period described above if:

- we distribute less cash than we have assumed in making this projection;
- we make a future offering of units and use the proceeds of the offering in a manner that does not produce additional deductions during the period described above, such as to repay indebtedness outstanding at the time of this offering or to acquire property that is not eligible for depreciation or amortization for federal income tax purposes during the period or that is depreciable or amortizable at a rate significantly slower than the rate applicable to our assets at the time of this offering;

- legislation is enacted that limits or repeals certain U.S. federal income tax preferences currently available to oil and gas exploration and production companies (please read "—Tax Treatment of Operations—Recent Legislative Developments").

Treatment of Distributions

Distributions by us to a unitholder generally will not be taxable to the unitholder unless such distributions exceed the unitholder's tax basis in its units, in which case the unitholder generally will recognize gain taxable in the manner described below under "—Disposition of Units."

Any reduction in a unitholder's share of our "liabilities" will be treated as a distribution by us of cash to that unitholder. A decrease in a unitholder's percentage interest in us because of our issuance of additional units may decrease the unitholder's share of our liabilities. For purposes of the foregoing, a unitholder's share of our nonrecourse liabilities (liabilities for which no partner bears the economic risk of loss) generally will be based upon that unitholder's share of the unrealized appreciation (or depreciation) in our assets, to the extent thereof, with any excess liabilities allocated based on the unitholder's share of our profits. Please read "—Disposition of Units."

A non-pro rata distribution of money or property (including a deemed distribution as a result of the reallocation of our liabilities described above) may cause a unitholder to recognize ordinary income, if the distribution reduces the unitholder's share of our "unrealized receivables," including depreciation and depletion recapture and substantially appreciated "inventory items," both as defined in Section 751 of the Code ("Section 751 Assets"). To the extent of such reduction, the unitholder would be deemed to receive its proportionate share of the Section 751 Assets and exchange such assets with us in return for a portion of the non-pro rata distribution. This deemed exchange generally will result in the unitholder's recognition of ordinary income in an amount equal to the excess of (1) the non-pro rata portion of that distribution over (2) the unitholder's tax basis (generally zero) in the Section 751 Assets deemed to be relinquished in the exchange.

Limitations on Deductibility of Losses

A unitholder may not be entitled to deduct the full amount of loss we allocate to it because its share of our losses will be limited to the lesser of (i) the unitholder's tax basis in its units, and (ii) in the case of a unitholder that is an individual, estate, trust or certain types of closely held corporations, the amount for which the unitholder is considered to be "at risk" with respect to our activities. In general, a unitholder will be at risk to the extent of its tax basis in its units, reduced by (1) any portion of that basis attributable to the unitholder's share of our liabilities, (2) any portion of that basis representing amounts otherwise protected against loss because of a guarantee, stop loss agreement or similar arrangement, and (3) any amount of money the unitholder borrows to acquire or hold its units, if the lender of those borrowed funds owns an interest in us, is related to another unitholder or can look only to the units for repayment. A unitholder subject to the at risk limitation must recapture losses deducted in previous years to the extent that distributions (including distributions deemed to result from a reduction in a unitholder's share of nonrecourse liabilities) cause the unitholder's at risk amount to be less than zero at the end of any taxable year.

Losses disallowed to a unitholder or recaptured as a result of the basis or at risk limitations will carry forward and will be allowable as a deduction in a later year to the extent that the unitholder's tax basis or at risk amount, whichever is the limiting factor, is subsequently increased. Upon a taxable disposition of units, any gain recognized by a unitholder can be offset by losses that were previously suspended by the at risk limitation but not losses suspended by the basis limitation. Any loss previously suspended by the at risk limitation in excess of that gain can no longer be used, and will not be available to offset a unitholder's salary or active business income.

In addition to the basis and at risk limitations, a passive activity loss limitation generally limits the deductibility of losses incurred by individuals, estates, trusts, some closely held corporations and personal service corporations from "passive activities" (generally, trade or business activities in which the taxpayer does not materially participate). The passive loss limitations are applied separately with respect to each publicly traded partnership. Consequently, any passive losses we generate will be available to offset only passive income generated by us. Passive losses that exceed a unitholder's share of passive income we generate may be deducted in full when the unitholder disposes of all of its units in a fully taxable transaction with an unrelated party. The passive loss rules generally are applied after other applicable limitations on deductions, including the at risk and basis limitations.

Limitations on Interest Deductions

The deductibility of a non-corporate taxpayer's "investment interest expense" generally is limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness allocable to property held for investment;
- interest expense allocated against portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent allocable against portfolio income.

The computation of a unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses other than interest directly connected with the production of investment income. Net investment income generally does not include qualified dividend income or gains attributable to the disposition of property held for investment. A unitholder's share of a publicly traded partnership's portfolio income and, according to the IRS, net passive income will be treated as investment income for purposes of the investment interest expense limitation.

Entity-Level Collections of Unitholder Taxes

If we are required or elect under applicable law to pay any federal, state, local, or non-U.S. tax on behalf of any current or former unitholder or our general partner, we are authorized to treat the payment as a distribution of cash to the relevant unitholder or general partner. Where the tax is payable on behalf of all unitholders or we cannot determine the specific unitholder on whose behalf the tax is payable, we are authorized to treat the payment as a distribution to all current unitholders. Payments by us as described above could give rise to an overpayment of tax on behalf of a unitholder, in which event the unitholder may be entitled to claim a refund of the overpayment amount. Unitholders are urged to consult their tax advisors to determine the consequences to them of any tax payment we make on their behalf.

Allocation of Income, Gain, Loss, and Deduction

Our items of income, gain, loss, and deduction generally will be allocated amongst our unitholders in accordance with their percentage interests in us.

Specified items of our income, gain, loss, and deduction will be allocated under Section 704(c) of the Code (or the principles of Section 704(c) of the Code) to account for any difference between the tax basis and fair market value of our assets at the time such assets are contributed to us and at the time of any subsequent offering of our units (a "Book-Tax Disparity"). As a result, the federal income tax burden associated with any Book-Tax Disparity immediately prior to an offering generally will be borne by our partners holding interests in us prior to the offering. In addition, items of recapture income will be specially allocated to the extent possible to the unitholder who was allocated the deduction giving rise to that recapture income in order to minimize the recognition of ordinary income by other unitholders.

An allocation of items of our income, gain, loss, or deduction, other than an allocation required by the Code to eliminate a Book-Tax Disparity, will generally be given effect for federal income tax purposes in determining a partner's share of an item of income, gain, loss, or deduction only if the allocation has "substantial economic effect." In any other case, a partner's share of an item will be determined on the basis of the partner's interest in us, which will be determined by taking into account all of the facts and circumstances, including (i) the partner's relative contributions to us, (ii) the interests of all of the partners in profits and losses, (iii) the interest of all of the partners in cash flow, and (iv) the rights of all of the partners to distributions of capital upon liquidation. Vinson & Elkins L.L.P. is of the opinion that, with the exception of the issues described in "—Section 754 Election" and "—Disposition of Units—Allocations Between Transferors and Transferees," allocations of income, gain, loss, or deduction under our partnership agreement will be given effect for federal income tax purposes.

Treatment of Securities Loans

A unitholder whose units are loaned (for example, a loan to a "short seller" to cover a short sale of units) may be treated as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period (i) any of our income, gain, loss, or deduction allocated to those units would not be reportable by the lending unitholder, and (ii) any cash distributions received by the unitholder as to those units may be treated as ordinary taxable income.

Due to a lack of controlling authority, Vinson & Elkins L.L.P. has not rendered an opinion regarding the tax treatment of a unitholder that enters into a securities loan with respect to its units. Unitholders desiring to assure their status as partners and avoid the risk of income recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and lending their units. The IRS has announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please read "—Disposition of Units—Recognition of Gain or Loss."

Tax Rates

Under current law, the highest marginal federal income tax rates for individuals applicable to ordinary income and long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) are 39.6% and 20%, respectively. These rates are subject to change by new legislation at any time.

In addition, a 3.8% net investment income tax ("NIIT") applies to certain net investment income earned by individuals, estates, and trusts. For these purposes, net investment income generally includes a unitholder's allocable share of our income and gain realized by a unitholder from a sale of units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income from all investments, or (ii) the amount by which the unitholder's modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if married filing separately) or $200,000 (if the unitholder is unmarried or in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

Section 754 Election

We will make the election permitted by Section 754 of the Code that permits us to adjust the tax bases in our assets as to specific purchasers of our units under Section 743(b) of the Code. That election is irrevocable without the consent of the IRS. The Section 743(b) adjustment separately applies to each purchaser of units based upon the values and bases of our assets at the time of the relevant purchase, and the adjustment will reflect the purchase price paid. The Section 743(b) adjustment does not apply to a person who purchases units directly from us.

Under our partnership agreement, we are authorized to take a position to preserve the uniformity of units even if that position is not consistent with applicable Treasury Regulations. A literal application of Treasury Regulations governing a 743(b) adjustment attributable to properties depreciable under Section 167 of the Code may give rise to differences in the taxation of unitholders purchasing units from us and unitholders purchasing from other unitholders. If we have any such properties, we intend to adopt methods employed by other publicly traded partnerships to preserve the uniformity of units, even if inconsistent with existing Treasury Regulations, and Vinson & Elkins L.L.P. has not opined on the validity of this approach. Please read "—Uniformity of Units."

The IRS may challenge the positions we adopt with respect to depreciating or amortizing the Section 743(b) adjustment we take to preserve the uniformity of units due to lack of controlling authority. Because a unitholder's tax basis for its units is reduced by its share of our items of deduction or loss, any position we take that understates deductions will overstate a unitholder's basis in its units, and may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read "—Disposition of Units—Recognition of Gain or Loss." If a challenge to such treatment were sustained, the gain from the sale of units may be increased without the benefit of additional deductions.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of our assets and other matters. The IRS could seek to reallocate some or all of any Section 743(b) adjustment we allocated to our assets subject to depreciation or depletion to goodwill or nondepreciable assets. Goodwill, as an intangible asset, is generally amortizable over a longer period of time or under a less accelerated method than our tangible assets. We cannot assure any unitholder that the determinations we make will not be successfully challenged by the IRS or that the resulting deductions will not be reduced or disallowed altogether. Should the IRS require a different tax basis adjustment to be made, and should, in our opinion, the expense of compliance exceed the benefit of the election, we may seek permission from the IRS to revoke our Section 754 election. If permission is granted, a subsequent purchaser of units may be allocated more income than it would have been allocated had the election not been revoked.

Tax Treatment of Operations

Accounting Method and Taxable Year

We will use the year ending December 31 as our taxable year and the accrual method of accounting for federal income tax purposes. Each unitholder will be required to include in its tax return its share of our income, gain, loss, and deduction for each taxable year ending within or with its taxable year. In addition, a unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of its units following the close of our taxable year but before the close of its taxable year must include its share of our income, gain, loss, and deduction in income for its taxable year, with the result that it will be required to include in income for its taxable year its share of more than one year of our income, gain, loss, and deduction. Please read "—Disposition of Units—Allocations Between Transferors and Transferees."

Depletion Deductions

Subject to the limitations on deductibility of losses discussed above (please read "—Limitations on Deductibility of Losses"), common unitholders will be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to our oil and gas interests. Although the Code requires each common unitholder to compute its own depletion allowance and maintain records of its share of the adjusted tax basis of the underlying property for depletion and other purposes, we intend to furnish each of our common unitholders with information relating to this computation for federal income tax purposes. Each common unitholder, however, remains responsible for calculating its own depletion allowance and maintaining records of its share of the adjusted tax basis of the underlying property for depletion and other purposes.

Percentage depletion is generally available with respect to common unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, gas, or derivative products or the operation of a major refinery. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the common unitholder's gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the common unitholder from the property for each taxable year, computed without the depletion allowance. A common unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the common unitholder's average daily production of domestic crude oil, or the gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil and gas production, with 6,000 cubic feet of domestic gas production regarded as equivalent to one barrel of crude oil. The 1,000-barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by these persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a common unitholder's total taxable income from all sources for the year, computed without the depletion allowance, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for the year plus the deduction carryover does not exceed 65% of the common unitholder's total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

Common unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (i) dividing the common unitholder's share of the adjusted tax basis in the underlying mineral-property by the number of mineral units (barrels of oil and thousand cubic feet, or Mcf, of gas) remaining as of the beginning of the taxable year and (ii) multiplying the result by the number of mineral units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the common unitholder's share of the total adjusted tax basis in the property.

All or a portion of any gain recognized by a common unitholder as a result of either the disposition by us of some or all of our oil and gas interests or the disposition by the common unitholder of some or all of its units may be taxed as ordinary income to the extent of recapture of depletion deductions, except for percentage depletion deductions in excess of the tax basis of the property. The amount of the recapture is generally limited to the amount of gain recognized on the disposition.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury Regulations relating to the availability and calculation of depletion deductions by the common unitholders. Further, because depletion is required to be computed separately by each common unitholder and not by us, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the unitholders for any taxable year. We encourage each prospective common unitholder to consult its tax advisor to determine whether percentage depletion would be available to the common unitholder.

Administrative Expenses

Expenses of the partnership will include administrative expenses, the deductibility of which may be subject to limitation. As long as we only own royalty interests, under applicable rules, administrative expenses attributable to common units will be considered miscellaneous itemized deductions that generally will have to be aggregated with an individual unitholder's other miscellaneous itemized deductions. These rules disallow itemized deductions that are less than 2% of a taxpayer's adjusted gross income, and the amount of otherwise allowable itemized deductions will be reduced by the lesser of (i) 3% of (A) adjusted gross income over

(B) $305,050 ($152,525 if married filing separately), and (ii) 80% of the amount of itemized deductions that are otherwise allowable, or both. It is anticipated that the amount of the administrative expenses will not be significant in relation to the partnership's income.

Recent Legislative Developments

The Obama Administration's budget proposals for fiscal years 2014 and 2015 include proposals that would, among other things, eliminate or reduce certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs ("IDCs"), (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these proposals will be introduced into law and, if so, how soon any resulting changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could increase the taxable income allocable to our unitholders and negatively impact the value of an investment in our units.

Tax Basis, Depreciation and Amortization

The tax basis of our assets will be used for purposes of computing depreciation and cost recovery deductions, if any, and, ultimately, gain or loss on the disposition of those assets. If we dispose of depreciable or depletable property by sale, foreclosure or otherwise, all or a portion of any gain, determined by reference to the amount of depreciation and depletion deductions previously taken, may be subject to the recapture rules and taxed as ordinary income rather than capital gain. Similarly, a unitholder who has taken cost recovery or depreciation deductions with respect to property we own will likely be required to recapture some or all of those deductions as ordinary income upon a sale of its interest in us. Please read "—Tax Consequences of Unit Ownership—Allocation of Income, Gain, Loss and Deduction."

The costs we incur in offering and selling our units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon our termination. While there are uncertainties regarding the classification of costs as organization expenses, which may be amortized by us, and as syndication expenses, which may not be amortized by us, the underwriting discounts we incur will be treated as syndication expenses. Please read "Disposition of Units—Recognition of Gain or Loss."

Valuation and Tax Basis of Our Properties

The federal income tax consequences of the ownership and disposition of units will depend in part on our estimates of the relative fair market values and the tax bases of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we will make many of the relative fair market value estimates ourselves. These estimates and determinations of tax basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss, or deduction previously reported by unitholders could change, and unitholders could be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

Disposition of Units

Recognition of Gain or Loss

A unitholder will be required to recognize gain or loss on a sale of units equal to the difference between the unitholder's amount realized and tax basis in the units sold. A unitholder's amount realized generally will equal the sum of the cash and the fair market value of other property it receives plus its share of our liabilities with respect to the units sold. Because the amount realized includes a unitholder's share of our liabilities, the gain recognized on the sale of units could result in a tax liability in excess of any cash received from the sale.

Except as noted below, gain or loss recognized by a unitholder on the sale or exchange of a unit held for more than one year generally will be taxable as long-term capital gain or loss. However, gain or loss recognized on the disposition of units will be separately computed and taxed as ordinary income or loss under Section 751 of the Code to the extent attributable to Section 751 Assets, such as depreciation or depletion recapture and our "inventory items," regardless of whether an inventory item is substantially appreciated in value. Ordinary income attributable to Section 751 Assets may exceed net taxable gain realized on the sale of a unit and may be recognized even if there is a net taxable loss realized on the sale of a unit. Thus, a unitholder may recognize both ordinary income and capital gain or loss upon a sale of units. Net capital loss may offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year.

For purposes of calculating gain or loss on the sale of units, the unitholder's adjusted tax basis will be adjusted by its allocable share of our income or loss in respect of its units for the year of the sale. Furthermore, as described above, the IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all of those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in its entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership.

Treasury Regulations under Section 1223 of the Code allow a selling unitholder who can identify units transferred with an ascertainable holding period to elect to use the actual holding period of the units transferred. Thus, according to the ruling discussed in the paragraph above, a unitholder will be unable to select high or low basis units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, it may designate specific units sold for purposes of determining the holding period of the units transferred. A unitholder electing to use the actual holding period of units transferred must consistently use that identification method for all subsequent sales or exchanges of our units. A unitholder considering the purchase of additional units or a sale of units purchased in separate transactions is urged to consult its tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" financial position, including a partnership interest with respect to which gain would be recognized if it were sold, assigned or terminated at its fair market value, in the event the taxpayer or a related person enters into:

- a short sale;
- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is authorized to issue Treasury Regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees

In general, our taxable income or loss will be determined quarterly, will be prorated on a monthly basis and will be subsequently apportioned among the unitholders in proportion to the number of units owned by each of them as of the opening of the applicable exchange on the first business day of the month (the "Allocation Date").

However, gain or loss realized on a sale or other disposition of our assets or, in the discretion of the general partner, any other extraordinary item of income, gain, loss, or deduction will be allocated among the unitholders on the Allocation Date in the month in which such income, gain, loss, or deduction is recognized. As a result, a unitholder transferring units may be allocated income, gain, loss, and deduction realized after the date of transfer.

Although simplifying conventions are contemplated by the Code and most publicly traded partnerships use similar simplifying conventions, the use of this method may not be permitted under existing Treasury Regulations. The Department of the Treasury has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders, although such tax items must be prorated on a daily basis. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. Accordingly, Vinson & Elkins L.L.P. is unable to opine on the validity of this method of allocating income and deductions between transferee and transferor unitholders. If this method is not allowed under the final Treasury Regulations, or only applies to transfers of less than all of the unitholder’s interest, our taxable income or losses could be reallocated among our unitholders. We are authorized to revise our method of allocation between transferee and transferor unitholders, as well as among unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

A unitholder who disposes of units prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss, and deduction attributable to the month of disposition but will not be entitled to receive a cash distribution for that period.

Notification Requirements

A unitholder who sells or purchases any of its units is generally required to notify us in writing of that transaction within 30 days after the transaction (or, if earlier, January 15 of the year following the transaction in the case of a seller). Upon receiving such notifications, we are required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify us of a transfer of units may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who effects the sale through a broker who will satisfy these requirements.

Constructive Termination

We will be considered to have “constructively” terminated as a partnership for federal income tax purposes upon the sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For such purposes, multiple sales of the same unit are counted only once. A constructive termination results in the closing of our taxable year for all unitholders. In the case of a unitholder reporting on a taxable year other than the calendar year, the closing of our taxable year may result in more than twelve months of our taxable income or loss being includable in a unitholder’s taxable income for the year of termination.

A constructive termination occurring on a date other than December 31 generally would require that we file two tax returns for one fiscal year thereby increasing our administration and tax preparation costs. However, pursuant to an IRS relief procedure the IRS may allow a constructively terminated partnership to provide a single Schedule K-1 for the calendar year in which a termination occurs. Following a constructive termination, we would be required to make new tax elections, including a new election under Section 754 of the Code. A termination could also result in penalties if we were unable to determine that the termination had occurred. Moreover, a termination may either accelerate the application of, or subject us to, any tax legislation enacted before the termination that would not otherwise have been applied to us as a continuing as opposed to a terminating partnership.

Uniformity of Units

Because we cannot match transferors and transferees of units and other reasons, we must maintain uniformity of the economic and tax characteristics of the units to a purchaser of these units. In the absence of uniformity, we may be unable to completely comply with a number of federal income tax requirements. Any non-uniformity could have a negative impact on the value of the units. Please read "—Tax Consequences of Unit Ownership—Section 754 Election."

Our partnership agreement permits our general partner to take positions in filing our tax returns that preserve the uniformity of our units. These positions may include reducing the depreciation, amortization or loss deductions to which a unitholder would otherwise be entitled or reporting a slower amortization of Section 743(b) adjustments for some unitholders than that to which they would otherwise be entitled. Vinson & Elkins L.L.P. is unable to opine as to the validity of such filing positions.

A unitholder's basis in units is reduced by its share of our deductions (whether or not these deductions were claimed on an individual income tax return) so that any position that we take that understates deductions will overstate the unitholder's basis in its units, and may cause the unitholder to understate gain or overstate loss on any sale of such units. Please read "—Disposition of Units—Recognition of Gain or Loss" above and "—Tax Consequences of Unit Ownership—Section 754 Election" above. The IRS may challenge one or more of any positions we take to preserve the uniformity of units. If such a challenge were sustained, the uniformity of units might be affected, and, under some circumstances, the gain from the sale of units might be increased without the benefit of additional deductions.

Tax-Exempt Organizations and Other Investors

Ownership of units by employee benefit plans and other tax-exempt organizations as well as by non-resident alien individuals, non-U.S. corporations and other non-U.S. persons (collectively, "non-U.S. unitholders") raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them. Prospective unitholders that are tax-exempt entities or non-U.S. unitholders should consult their tax advisors before investing in our units. Employee benefit plans and most other tax-exempt organizations, including IRAs and other retirement plans, are subject to federal income tax on unrelated business taxable income. Because our properties may be financed with debt and because we may own working interests in the future, portions of our income may be unrelated business taxable income and may be taxable to a tax-exempt unitholder.

Non-U.S. unitholders are taxed by the United States on income effectively connected with the conduct of a U.S. trade or business ("effectively connected income") and on certain types of U.S.-source non-effectively connected income (such as dividends and royalties), unless exempted or further limited by an income tax treaty. At the time of the IPO, we will have income from our royalty interests, certain investments in forward contracts, mineral lease bonus and delay rentals, management fees, and working interests in oil and natural gas properties. Even though we are not the operator, our ownership of working interests may be treated as effectively connected income. Furthermore, it is probable that we will be deemed to conduct these activities through permanent establishments in the United States within the meaning of applicable tax treaties. Consequently, a non-U.S. unitholder may be required to file federal tax returns to report its share of our income, gain, loss, or deduction, and pay federal income tax on its share of our net income or gain in a manner similar to a taxable U.S. unitholder. Moreover, under rules concerning withholding on effectively connected income applicable to publicly traded partnerships, distributions to non-U.S. unitholders are subject to withholding at the highest applicable effective tax rate. Even though at the time of the IPO, not all of our income will be effectively connected income, we will instruct brokers and nominees to withhold on all distributions to non-U.S. holders at the highest applicable effective tax rate based upon the convention for effectively connected income. Non-U.S. unitholders may be entitled to a refund of all or a portion of this amount. Each non-U.S. unitholder that obtains a taxpayer identification number from the IRS and submits that number to our transfer agent on a Form W-8BEN or W-8BEN-E (or applicable substitute form) may obtain credit for these withholding taxes.

In addition, because a non-U.S. unitholder classified as a corporation may be treated as engaged in a U.S. trade or business, that corporation may be subject to the U.S. branch profits tax at a rate of 30%, in addition to regular federal income tax, on its share of our income and gain as adjusted for changes in the foreign corporation's "U.S. net equity" to the extent reflected in the corporation's effectively connected earnings and profits. That tax may be reduced or eliminated by an income tax treaty between the United States and the country in which the foreign corporate unitholder is a "qualified resident." In addition, this type of unitholder is subject to special information reporting requirements under Section 6038C of the Code.

A non-U.S. unitholder who sells or otherwise disposes of a unit will be subject to federal income tax on gain realized from the sale or disposition of that unit to the extent the gain is effectively connected with a U.S. trade or business of the non-U.S. unitholder. Under a ruling published by the IRS interpreting the scope of "effectively connected income," gain recognized by a non-U.S. person from the sale of its interest in a partnership that is engaged in a trade or business in the United States will be considered to be effectively connected with a U.S. trade or business. Thus, part or all of a non-U.S. unitholder's gain from the sale or other disposition of its units may be treated as effectively connected with a unitholder's indirect U.S. trade or business constituted by its investment in us. Moreover, under the Foreign Investment in Real Property Tax Act, a non-U.S. unitholder generally will be subject to federal income tax upon the sale or disposition of a unit if (i) it owned (directly or indirectly, actually or constructively, applying certain attribution rules) more than 5% of our units at any time during the five-year period ending on the date of such disposition, and (ii) 50% or more of the fair market value of our worldwide real-property interests and our other assets used or held for use in a trade or business consisted of U.S. real-property interests (which include U.S. real estate (including land, improvements, and certain associated personal property) and interests in certain entities holding U.S. real estate) at any time during the shorter of the period during which a unitholder held the units or the five-year period ending on the date of disposition. More than 50% of our assets may consist of U.S. real-property interests. Therefore, non-U.S. unitholders may be subject to federal income tax on gain from the sale or disposition of their units.

Administrative Matters

Information Returns and Audit Procedures

We intend to furnish to each unitholder, within 90 days after the close of each taxable year, specific tax information, including a Schedule K-1, which describes its share of our income, gain, loss, and deduction for our preceding taxable year. In preparing this information, which will not be reviewed by counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each unitholder's share of income, gain, loss, and deduction. We cannot assure our unitholders that those positions will yield a result that conforms to all of the requirements of the Code, Treasury Regulations or administrative interpretations of the IRS.

The IRS may audit our federal income tax information returns. Neither we nor Vinson & Elkins L.L.P. can assure prospective unitholders that the IRS will not successfully challenge the positions we adopt, and such a challenge could adversely affect the value of the units. Adjustments resulting from an IRS audit may require each unitholder to adjust a prior year's tax liability and may result in an audit of the unitholder's own return. Any audit of a unitholder's return could result in adjustments unrelated to our returns.

Publicly traded partnerships generally are treated as entities separate from their owners for purposes of federal income tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss, and deduction are determined in a partnership proceeding rather than in separate proceedings of the partners. The Code requires that one partner be designated as the "Tax Matters Partner" for these purposes, and our partnership agreement designates our general partner.

The Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a 1% profits interest in us to a settlement with the IRS unless that unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all of the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least a 1% interest in profits or by any group of unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review may go forward, and each unitholder with an interest in the outcome may participate in that action.

A unitholder must file a statement with the IRS identifying the treatment of any item on its federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest in us as a nominee for another person are required to furnish to us:

(1) the name, address, and taxpayer identification number of the beneficial owner and the nominee;

(2) a statement regarding whether the beneficial owner is:

  (a) a non-U.S. person;

  (b) a non-U.S. government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

  (c) a tax-exempt entity;

(3) the amount and description of units held, acquired or transferred for the beneficial owner; and

(4) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $100 per failure, up to a maximum of $1.5 million per calendar year, is imposed by the Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

Accuracy-Related Penalties

Certain penalties may be imposed as a result of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for the underpayment of that portion and that the taxpayer acted in good faith regarding the underpayment of that portion. We do not anticipate that any accuracy related penalties will be assessed against us.

FATCA Withholding Requirements

Under the Foreign Account Tax Compliance Act (“FATCA”), a withholding agent may be required to withhold 30% of any interest, dividends and other fixed or determinable annual or periodical gains, profits, and income from sources within the United States (“FDAP Income”) or gross proceeds from the sale of any property of a type which can produce interest or dividends from sources within the United States paid to (i) a foreign financial institution (which includes foreign broker-dealers, clearing organizations, investment companies, hedge funds, and certain other investment entities) unless the foreign financial institution agrees to verify, report, and disclose its U.S. account holders and meets certain other specified requirements or (ii) a non-financial foreign entity that is a beneficial owner of the payment unless the entity certifies that it does not have any substantial U.S. owners or provides the name, address, and taxpayer identification number of each substantial U.S. owner and the entity meets certain other specified requirements or otherwise qualifies for an exemption from this withholding.

The withholding provisions described above are scheduled to apply to payments of FDAP Income made on or after July 1, 2014 and to payments of relevant gross proceeds made on or after January 1, 2017. Each prospective unitholder should consult its own tax advisor regarding these withholding provisions.

State, Local, and Other Tax Considerations

In addition to federal income taxes, unitholders may be subject to other taxes, including state and local income taxes, unincorporated business taxes, and estate, inheritance, or intangibles taxes that may be imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if you do not live in those jurisdictions. We will initially own assets and conduct business in several states, many of which impose a personal income tax and also impose income taxes on corporations and other entities. We may also own property or do business in other states in the future that impose income or similar taxes on nonresident individuals. Although an analysis of those various taxes is not presented here, each prospective unitholder should consider their potential impact on its investment in us.

Although you may not be required to file a return and pay taxes in some jurisdictions because your income from that jurisdiction falls below the filing and payment requirement, you will be required to file income tax returns and to pay income taxes in jurisdictions in which we do business or own property and may be subject to penalties for failure to comply with those requirements. It is your responsibility to file all U.S. federal, foreign, state, and local tax returns. Our counsel has not rendered an opinion on the foreign, state, or local tax consequences of an investment in our common units.

It is the responsibility of each unitholder to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of his investment in us. We strongly recommend that each prospective unitholder consult, and depend upon, its own tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local, and non-U.S., as well as U.S. federal tax returns that may be required of it. Vinson & Elkins L.L.P. has not rendered an opinion on the state, local, alternative minimum tax or non-U.S. tax consequences of an investment in us.

INVESTMENT IN BLACK STONE MINERALS, L.P. BY EMPLOYEE BENEFIT PLANS

An investment in our common units by an employee benefit plan is subject to additional considerations because the investments of these plans are subject to the fiduciary responsibility and prohibited transaction provisions of ERISA and the prohibited transaction restrictions imposed by Section 4975 of the Internal Revenue Code and may be subject to provisions under certain federal, state, local, non-U.S. or other laws or regulations that are similar to such provisions of the Internal Revenue Code or ERISA (collectively, “Similar Laws”). For these purposes the term “employee benefit plan” includes, but is not limited to, qualified pension, profit-sharing and stock bonus plans, certain Keogh plans, certain simplified employee pension plans and tax deferred annuities or individual retirement accounts or annuities (“IRAs”) and entities whose underlying assets are considered to include “plan assets” of such plans, accounts or arrangements.

General Fiduciary Matters

ERISA and the Internal Revenue Code impose certain duties on persons who are fiduciaries of an employee benefit plan that is subject to Title I of ERISA or Section 4975 of the Internal Revenue Code (an “ERISA Plan”) and prohibit certain transactions involving the assets of an ERISA Plan and its fiduciaries or other interested parties. Under ERISA and the Internal Revenue Code, any person who exercises any discretionary authority or control over the administration of an ERISA Plan or the management or disposition of the assets of an ERISA Plan, or who renders investment advice for a fee or other compensation to an ERISA Plan, is generally considered to be a fiduciary of the ERISA Plan. In considering an investment in our common units, among other things, consideration should be given to:

- whether the investment is prudent under Section 404(a)(1)(B) of ERISA and any other applicable Similar Laws;
- whether, in making the investment, the employee benefit plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws;
- whether the investment is permitted under the terms of the applicable documents governing the employee benefit plan;
- whether making the investment will comply with the delegation of control and prohibited transaction provisions under Section 406 of ERISA, Section 4975 of the Internal Revenue Code and any other applicable Similar Laws (please read the discussion under “—Prohibited Transaction Issues” below);
- whether in making the investment, the employee benefit plan will be considered to hold, as plan assets, (1) only the investment in our common units, or (2) an undivided interest in our underlying assets (please read the discussion under “—Plan Asset Issues” below); and
- whether the investment will result in recognition of unrelated business taxable income by the employee benefit plan and, if so, the potential after-tax investment return. Please read “Material U.S. Federal Income Tax Consequences—Tax-Exempt Organizations and Other Investors.”

The person with investment discretion with respect to the assets of an employee benefit plan, often called a fiduciary, should determine whether an investment in our common units is authorized by the appropriate governing instruments and is a proper investment for the employee benefit plan or IRA.

Prohibited Transaction Issues

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit employee benefit plans and certain IRAs that are not considered part of an employee benefit plan from engaging in specified transactions involving “plan assets” with parties that are “parties in interest” under ERISA or “disqualified persons” under the Internal Revenue Code with respect to the employee benefit plan or IRA, unless an exemption is applicable. A party in interest or disqualified person who engages in a non-exempt prohibited transaction may be subject to excise taxes and other penalties and liabilities under ERISA and the Internal Revenue Code. In addition, the fiduciary of the ERISA Plan that engaged in such a prohibited transaction may be subject to excise taxes, penalties and liabilities under ERISA and the Internal Revenue Code.

Plan Asset Issues

In addition to considering whether the purchase of our common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in our common units, be deemed to own an undivided interest in our assets, with the result that our general partner also would be a fiduciary of the plan and our operations would be subject to the regulatory restrictions of ERISA, including its prohibited transaction rules, as well as the prohibited transaction rules of the Internal Revenue Code and any other applicable Similar Laws.

The Department of Labor regulations provide guidance with respect to whether the assets of an entity in which employee benefit plans acquire equity interests would be deemed "plan assets" under certain circumstances. Under these regulations, an entity's underlying assets generally would not be considered to be "plan assets" if, among other things:

(1) the equity interests acquired by employee benefit plans are publicly offered securities—i.e., the equity interests are part of a class of securities that are widely held by 100 or more investors independent of the issuer and each other, "freely transferable" (as defined in the applicable Department of Labor regulations) and either part of a class of securities registered pursuant to certain provisions of the federal securities laws or sold to the plan as part of a public offering under certain conditions;

(2) the entity is an "operating company"—i.e., it is primarily engaged in the production or sale of a product or service other than the investment of capital either directly or through a majority-owned subsidiary or subsidiaries; or

(3) there is no significant investment by benefit plan investors, which is defined to mean that, immediately after the most recent acquisition of an equity interest in any entity by an employee benefit plan, less than 25% of the total value of each class of equity interest, disregarding certain interests held by our general partner, its affiliates, and certain other persons, is held by the employee benefit plans and IRAs referred to above.

With respect to an investment in our common units, we believe that our assets should not be considered "plan assets" under these regulations because it is expected that the investment will satisfy the requirements in (1) and (2) above and may also satisfy the requirements in (3) above (although we do not monitor the level of investment by benefit plan investors as required for compliance with (3)).

The foregoing discussion of issues arising for employee benefit plan investments under ERISA, the Internal Revenue Code and applicable Similar Laws is general in nature and is not intended to be all inclusive, nor should it be construed as legal advice. Plan fiduciaries contemplating a purchase of our common units should consult with their own counsel regarding the consequences of a purchase under ERISA, the Internal Revenue Code and Similar Laws in light of the serious penalties, excise taxes, and liabilities imposed on persons who engage in prohibited transactions or other violations.

Table of Contents

UNDERWRITING

Barclays Capital Inc. is acting as the representative of the underwriters and as the sole book-running manager of this offering. Under the terms of an underwriting agreement, which will be filed as an exhibit to the registration statement relating to this prospectus, each of the underwriters named below has severally agreed to purchase from us the respective number of common units shown opposite its name below:

Underwriters	Number of Common Units
Barclays Capital Inc.	
Total	

The underwriting agreement provides that the underwriters' obligation to purchase the common units depends on the satisfaction of the conditions contained in the underwriting agreement including:

- the obligation to purchase all of the common units offered hereby (other than those common units covered by their option to purchase additional common units as described below), if any of the common units are purchased;
- the representations and warranties made by us to the underwriters are true;
- there is no material change in our business or the financial markets; and
- we deliver customary closing documents to the underwriters.

Commissions and Expenses

The following table summarizes the underwriting discounts we will pay to the underwriters. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional common units. The underwriting fee is the difference between the initial price to the public and the amount the underwriters pay to us for the common units.

	No Exercise	Full Exercise
Per common unit	$	$
Total	$	$

The representative of the underwriters has advised us that the underwriters propose to offer the common units directly to the public at the public offering price on the cover of this prospectus and to selected dealers, which may include the underwriters, at an offering price less a selling concession not in excess of $ per common unit. After the offering, the representative may change the offering price and other selling terms. Sales of common units made outside of the United States may be made by affiliates of the underwriters. The offering of the common units by the underwriters is subject to receipt and acceptance and subject to the underwriters' right to reject any order in whole or in part.

We estimate that the expenses of this offering incurred by us will be $ million (excluding underwriting discounts).

Option to Purchase Additional Common Units

We have granted the underwriters an option exercisable for 30 days after the date of the underwriting agreement, to purchase, from time to time, in whole or in part, up to an aggregate of additional common units at the public offering price less underwriting discounts. This option may be exercised if the underwriters sell more than common units in connection with this offering. To the extent that this option is exercised, each underwriter will be obligated, subject to certain conditions, to purchase its pro rata portion of these additional common units based on the underwriter's underwriting commitment in the offering as indicated in the table at the beginning of this Underwriting section.

Lock-Up Agreements

We, our general partner and its affiliates, the directors, and executive officers of our general partner have agreed that, without the prior written consent of Barclays Capital Inc., we and they will not directly or indirectly, for a period of 180 days after the date of this prospectus (1) offer for sale, sell, pledge, or otherwise dispose of (or enter into any transaction or device that is designed to, or could be expected to, result in the disposition by any person at any time in the future of) any of our common units (including, without limitation, common units that may be deemed to be beneficially owned by us or them in accordance with the rules and regulations of the SEC and common units that may be issued upon exercise of any options or warrants) or securities convertible into or exercisable or exchangeable for common units (other than (i) the common units being sold in this offering, and (ii) common units issued pursuant to employee benefit plans, qualified option plans or other employee compensation plans existing on the date hereof), (2) enter into any swap or other derivatives transaction that transfers to another, in whole or in part, any of the economic consequences of ownership of the common units, (3) make any demand for or exercise any right or file or cause to be filed a registration statement, including any amendments thereto, with respect to the registration of any common units or securities convertible, exercisable or exchangeable into common units or any of our other securities (other than any registration statement on Form S-8), or (4) publicly disclose the intention to do any of the foregoing.

Barclays Capital Inc., in its sole discretion, may release the common units and other securities subject to the lock-up agreements described above in whole or in part at any time with or without notice. When determining whether or not to release common units and other securities from lock-up agreements, Barclays Capital Inc. will consider, among other factors, the holder's reasons for requesting the release, the number of common units and other securities for which the release is being requested and market conditions at the time.

Offering Price Determination

Prior to this offering, there has been no public market for our common units. The initial public offering price will be negotiated between the representative and us. In determining the initial public offering price of our common units, the representative will consider:

- the history and prospects for the industry in which we compete;
- our financial information;
- the ability of our management and our business potential and earning prospects;
- the prevailing securities markets at the time of this offering; and
- the recent market prices of, and the demand for, publicly traded common units of generally comparable companies.

Indemnification

We have agreed to indemnify the several underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments that the underwriters may be required to make for these liabilities.

Stabilization, Short Positions, and Penalty Bids

The representative may engage in stabilizing transactions, short sales, purchases to cover positions created by short sales, and penalty bids or purchases for the purpose of pegging, fixing, or maintaining the price of the common units, in accordance with Regulation M under the Exchange Act:

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.
- A short position involves a sale by the underwriters of common units in excess of the number of common units the underwriters are obligated to purchase in the offering, which creates the syndicate short position. This short position may be either a covered short position or a naked short position. In a covered short position, the number of common units involved in the sales made by the underwriters in excess of the number of common units they are obligated to purchase is not greater than the number of common units that they may purchase by exercising their option to purchase additional common units.

In a naked short position, the number of common units involved is greater than the number of common units in their option to purchase additional common units. The underwriters may close out any short position by either exercising their option to purchase additional common units and/or purchasing common units in the open market. In determining the source of common units to close out the short position, the underwriters will consider, among other things, the price of common units available for purchase in the open market as compared to the price at which they may purchase common units through their option to purchase additional common units. A naked short position is more likely to be created if the underwriters are concerned that there could be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in the offering.

- Syndicate covering transactions involve purchases of the common units in the open market after the distribution has been completed in order to cover syndicate short positions.
- Penalty bids permit the representative to reclaim a selling concession from a syndicate member when the common units originally sold by the syndicate member are purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions, and penalty bids may have the effect of raising or maintaining the market price of our common units or preventing or retarding a decline in the market price of the common units. As a result, the price of the common units may be higher than the price that might otherwise exist in the open market. These transactions may be effected on the NYSE or otherwise and, if commenced, may be discontinued at any time.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common units. In addition, neither we nor any of the underwriters make any representation that the representative will engage in these stabilizing transactions or that any transaction, once commenced, will not be discontinued without notice.

Electronic Distribution

A prospectus in electronic format may be made available on the internet sites or through other online services maintained by one or more of the underwriters and/or selling group members participating in this offering, or by their affiliates. In those cases, prospective investors may view offering terms online and, depending upon the particular underwriter or selling group member, prospective investors may be allowed to place orders online. The underwriters may agree with us to allocate a specific number of common units for sale to online brokerage account holders. Any allocation for online distributions will be made by the representative on the same basis as other allocations.

Other than the prospectus in electronic format, the information on any underwriter’s or selling group member’s web site and any information contained in any other web site maintained by an underwriter or selling group member is not part of the prospectus or the registration statement of which this prospectus forms a part, has not been approved and/or endorsed by us or any underwriter or selling group member in its capacity as underwriter or selling group member and should not be relied upon by investors.

New York Stock Exchange

We intend to apply to list our common units on the NYSE under the symbol “BSM.” The underwriters have undertaken to sell the minimum number of common units to the minimum number of beneficial owners necessary to meet the NYSE distribution requirements for trading.

Discretionary Sales

The underwriters have informed us that they do not intend to confirm sales to discretionary accounts that exceed 5% of the total number of common units offered by them.

Stamp Taxes

If you purchase common units offered in this prospectus, you may be required to pay stamp taxes and other charges under the laws and practices of the country of purchase, in addition to the offering price listed on the cover page of this prospectus.

Relationships

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include sales and trading, commercial and investment banking, advisory, investment management, investment research, principal investment, hedging, market making, brokerage, and other financial and non-financial activities and services. The underwriters and their affiliates have in the past, and may in the future, perform investment banking, commercial banking, advisory, and other services for us and our respective affiliates from time to time for which they have received, and may in the future receive, customary fees and expenses.

In addition, in the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments, including serving as counterparties to certain derivative and hedging arrangements, and actively trade debt and equity securities (or related derivative securities), and financial instruments (including bank loans) for their own account and for the accounts of their customers. Such investment and securities activities may involve securities and instruments of ours or our affiliates. The underwriters and their respective affiliates may also make investment recommendations or publish or express independent research views in respect of these securities or financial instruments and may hold, or recommend to clients that they acquire, long or short positions in these securities and instruments.

FINRA

Because the Financial Industry Regulatory Authority, Inc., or FINRA, is expected to view the common units offered hereby as interests in a direct participation program, the offering is being made in compliance with Rule 2310 of the FINRA Rules. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for trading on a national securities exchange.

Selling Restrictions

European Economic Area

This prospectus has been prepared on the basis that the transactions contemplated by this prospectus in any Member State of the European Economic Area which has implemented the Prospectus Directive (each, a “Relevant Member State”) (other than Germany) will be made pursuant to an exemption under the Prospectus

Directive from the requirement to publish a prospectus for offers of securities. Accordingly, any person making or intending to make any offer in that Relevant Member State of the securities which are the subject of the transactions contemplated by this prospectus, may only do so in circumstances in which no obligation arises for us or any of the underwriters to publish a prospectus pursuant to Article 3 of the Prospectus Directive in relation to an offer. Neither we nor any of the underwriters have authorized, nor do they authorize, the making of any offer of securities or any invitation relating thereto in circumstances in which an obligation arises for us or any of the underwriters to publish a prospectus for an offer or invitation.

In relation to each Relevant Member State, other than Germany, with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the “Relevant Implementation Date”), no offer to the public of the securities subject to this supplement has been or will be made in that Relevant Member State other than:

- to any legal entity which is a qualified investor as defined in the Prospectus Directive (“Qualified Investors”);
- to fewer than 100 or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than Qualified Investors), as permitted under the Prospectus Directive subject to obtaining our prior consent for anysuch offer; or
- in any other circumstances falling within Article 3(2) of the Prospectus Directive,

provided that no such offer or invitation shall require us or any of the underwriters to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, the expression an “offer to the public” means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase the securities, as the same may be further defined in that Relevant Member State by any measure implementing the Prospectus Directive in that Member State. The expression “Prospectus Directive” means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in each Relevant Member State, and the expression “2010 Amending Directive” means Directive 2010/73/EU.

We have not authorized and do not authorize the making of any offer of securities through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the securities as contemplated in this prospectus. Accordingly, no purchaser of the securities, other than the underwriters, is authorized to make any further offer of the securities on behalf of us or the underwriters.

United Kingdom

We may constitute a “collective investment scheme” as defined by section 235 of the Financial Services and Markets Act 2000 (“FSMA”) that is not a “recognised collective investment scheme” for the purposes of FSMA (“CIS”) and that has not been authorised or otherwise approved. As an unregulated scheme, it cannot be marketed in the United Kingdom to the general public, except in accordance with FSMA. This prospectus is only being distributed in the United Kingdom to, and are only directed at (i) investment professionals falling within the description of persons in Article 14(5) of the Financial Services and Markets Act 2000 (Promotion of Collective Investment Schemes) Order 2001, as amended (the “CIS Promotion Order”) or Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the “Financial Promotion Order”), (ii) high net worth companies and other persons falling with Article 22(2)(a) to (d) of the CIS Promotion Order or Article 49(2)(a) to (d) of the Financial Promotion Order, or (iii) to any other person to whom it may otherwise lawfully be made, (all such persons together being referred to as “relevant persons”). Our common units are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire our common units will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this prospectus or any of its contents.

Switzerland

The distribution of our common units in Switzerland will be exclusively made to, and directed at, regulated qualified investors ("Regulated Qualified Investors"), as defined in Article 10(3)(a) and (b) of the Swiss Collective Investment Schemes Act of 23 June 2006, as amended ("CISA").

Accordingly, we have not, and will not be, registered with the Swiss Financial Market Supervisory Authority ("FINMA") and no Swiss representative or paying agent has been or will be appointed for us in Switzerland. This prospectus and/or any other offering materials relating to our common units may be made available in Switzerland solely to Regulated Qualified Investors.

Germany

This prospectus has not been prepared in accordance with the requirements for a securities or sales prospectus under the German Securities Prospectus Act (*Wertpapierprospektgesetz*), the German Asset Investment Act (*Vermôgensanlagengesetz*), or the German Investment Act (*Investmentgesetz*). Neither the German Federal Financial Services Supervisory Authority (*Bundesanstalt für Finanzdienstleistungsaufsicht*—BaFin) nor any other German authority has been notified of the intention to distribute our common units in Germany. Consequently, our common units may not be distributed in Germany by way of public offering, public advertisement or in any similar manner and this prospectus and any other document relating to the offering, as well as information or statements contained therein, may not be supplied to the public in Germany or used in connection with any offer for subscription of our common units to the public in Germany or any other means of public marketing. Our common units are being offered and sold in Germany only to qualified investors which are referred to in Section 3, paragraph 2 no. 1 in connection with Section 2 no. 6 of the German Securities Prospectus Act, Section 2 no. 4 of the German Asset Investment Act, and in Section 2 paragraph 11 sentence 2 no.1 of the German Investment Act. This prospectus is strictly for use of the person who has received it. It may not be forwarded to other persons or published in Germany.

The offering does not constitute an offer to sell or the solicitation or an offer to buy our common units in any circumstances in which such offer or solicitation is unlawful.

Netherlands

Our common units may not be offered or sold, directly or indirectly, in the Netherlands, other than to qualified investors (*gekwalificeerde beleggers*) within the meaning of Article 1:1 of the Dutch Financial Supervision Act (*Wet op het financieel toezicht*).

Singapore

This prospectus has not been and will not be registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the common units may not be circulated or distributed, nor may the common units be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person pursuant to Section 275(1), or any person pursuant to Section 275(1A), and in accordance with the conditions specified in Section 275, of the SFA, or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the common units are subscribed or purchased under Section 275 of the SFA by a relevant person which is:

(1) a corporation (which is not an accredited investor (as defined in Section 4A of the SFA)) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or

(2) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary of the trust is an individual who is an accredited investor, securities (as defined in Section 239(1) of the SFA) of that corporation or the beneficiaries' rights and interest (howsoever described) in that trust shall not be transferred within six months after that corporation or that trust has acquired the common units pursuant to an offer made under Section 275 of the SFA except:

(a) to an institutional investor or to a relevant person defined in Section 275(2) of the SFA, or to any person arising from an offer referred to in Section 275(1A) or Section 276(4)(i)(B) of the SFA;

(b) where no consideration is or will be given for the transfer;

(c) where the transfer is by operation of law;

(d) as specified in Section 276(7) of the SFA; or

(e) as specified in Regulation 32 of the Securities and Futures (Offers of Investments) (Shares and Debentures) Regulations 2005 of Singapore.

Hong Kong

Our common units may not be offered or sold in Hong Kong by means of this prospectus or any other document other than to (a) professional investors as defined in the Securities and Futures Ordinance of Hong Kong (Cap. 571, Laws of Hong Kong) ("SFO") and any rules made under the SFO, or (b) in other circumstances which do not result in this prospectus being deemed to be a "prospectus," as defined in the Companies Ordinance of Hong Kong (Cap. 32, Laws of Hong Kong) ("CO"), or which do not constitute an offer to the public within the meaning of the CO or the SFO; and no person has issued or had in possession for the purposes of issue, or will issue or has in possession for the purposes of issue, whether in Hong Kong or elsewhere, any advertisement, invitation or document relating to our common units which is directed at, or the contents of which are likely to be accessed or read by, the public of Hong Kong (except if permitted to do so under the securities laws of Hong Kong) other than with respect to our common units which are or are intended to be disposed of only to persons outside Hong Kong or only to professional investors as defined in the SFO.

LEGAL MATTERS

The validity of our common units and certain other legal matters will be passed upon for us by Vinson & Elkins L.L.P., New York, New York. Certain legal matters in connection with this offering will be passed upon for the underwriters by Andrews Kurth LLP.

EXPERTS

The consolidated financial statements of Black Stone Minerals Company, L.P. and Subsidiaries as of December 31, 2013 and 2012, and for the years then ended, included in this prospectus have been audited by UHY LLP, an independent registered public accounting firm as set forth in their report thereon appearing elsewhere herein, and are included in reliance upon such report, given on the authority of such firm as experts in auditing and accounting.

The balance sheet of Black Stone Minerals, L.P. as of September 16, 2014 included in this prospectus has been audited by UHY LLP, an independent registered public accounting firm as set forth in their report thereon appearing elsewhere herein, and is included in reliance upon such report, given on the authority of such firm as experts in auditing and accounting.

Information included in this prospectus regarding our estimated quantities of oil and natural gas reserves and the discounted present value of future net cash flows therefrom is based upon estimates of such reserves and present values prepared by Pressler Petroleum Consultants, Inc., third-party petroleum engineering firm, as of December 31, 2013. This information is included herein in reliance upon the authority of said firm as experts in these matters.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 (including the exhibits, schedules and amendments thereto) under the Securities Act with respect to the common units being offered hereunder. This prospectus does not contain all of the information set forth in the registration statement and the exhibits and schedules to the registration statement. For further information with respect to us and our common units, we refer you to the registration statement and the exhibits filed as a part of the registration statement. Statements contained in this prospectus concerning the contents of any contract or any other documents are not necessarily complete. If a contract or document has been filed as an exhibit to the registration statement, we refer you to the copy of the contract or document that has been filed as an exhibit and reference thereto is qualified in all respects by the terms of the filed exhibit.

As a result of this offering, we will become subject to the full informational requirements of the Exchange Act. We will fulfill our obligations with respect to such requirements by filing period reports and other information with the SEC. Our SEC filings, including the registration statement and any exhibits and schedules thereto, may be inspected without charge at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549, and copies of these materials may be obtained from that office after payment of fees prescribed by the SEC. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains a web site that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC at http://www.sec.gov. After this offering, documents filed by us can also be inspected at the offices of the NYSE Inc., 20 Broad Street, New York, New York 10002.

FORWARD-LOOKING STATEMENTS

Some of the information in this prospectus may contain forward-looking statements. Forward-looking statements give our current expectations, contain projections of results of operations or of financial condition, or forecasts of future events. Words such as “may,” “assume,” “forecast,” “position,” “predict,” “strategy,” “expect,” “intend,” “plan,” “estimate,” “anticipate,” “believe,” “project,” “budget,” “potential,” or “continue,” and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this prospectus. Actual results may vary materially. You are cautioned not to place undue reliance on any forward-looking statements. You should also understand that it is not possible to predict or identify all such factors and should not consider the following list to be a complete statement of all potential risks and uncertainties. Factors that could cause our actual results to differ materially from the results contemplated by such forward-looking statements include:

- our ability to execute our business strategies;
- the volatility of realized oil and natural gas prices;
- the level of production on our properties;
- regional supply and demand factors, delays, or interruptions of production;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete, and integrate acquisitions;
- general economic, business, or industry conditions;
- competition in the oil and natural gas industry;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services, or personnel;
- restrictions on the use of water;
- the availability of transportation facilities;
- the ability of our operators to comply with applicable governmental laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing;
- future operating results;
- exploration and development drilling prospects, inventories, projects, and programs;
- operating hazards faced by our operators;
- the ability of our operators to keep pace with technological advancements; and
- certain factors discussed elsewhere in this prospectus.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements.

Table of Contents

INDEX TO FINANCIAL STATEMENTS

BLACK STONE MINERALS, L.P.
UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

Introduction

Set forth below are the unaudited pro forma consolidated balance sheet as of June 30, 2014 and the unaudited pro forma consolidated statements of operations for the year ended December 31, 2013 and the six months ended June 30, 2014 (together with the notes to unaudited pro forma consolidated financial statements, the “pro forma financial statements”), of Black Stone Minerals, L.P. (the “Partnership”). The unaudited pro forma financial statements of the Partnership have been derived from the historical consolidated financial statements of Black Stone Minerals Company, L.P. (“BSMC,” the “Company” or the “Predecessor”). The unaudited pro forma financial statements should be read in conjunction with the Predecessor’s historical consolidated financial statements and the related financial statement notes, included elsewhere in this prospectus.

The Partnership will own and operate the business of the Predecessor effective with the closing of this offering (the “Offering”). The contribution of the Predecessor’s business to the Partnership will be recorded at cost, as it is a reorganization of entities under common control. The pro forma financial statements have been prepared on the assumption that Black Stone Minerals, L.P. will continue to be treated as a partnership for U.S. federal income tax purposes.

The unaudited pro forma adjustments are based on currently available information and certain estimates and assumptions. The actual effects of the events may differ from the unaudited pro forma adjustments. However, management believes the assumptions utilized to prepare the unaudited pro forma adjustments provide a reasonable basis for presenting the significant effects of the events identified above and as more specifically described below.

The unaudited pro forma consolidated balance sheet assumes the transactions to be effected as if the closing of the offering had taken place as of June 30, 2014, and the unaudited pro forma consolidated statements of operations for the year ended December 31, 2013 and the six months ended June 30, 2014 assume the transactions had taken place as of January 1, 2013.

The pro forma financial statements give pro forma effect to the following transactions:

- a cash contribution by Black Stone Natural Resources, L.L.C. (“BSNR”), the general partner of BSMC and the Partnership and a wholly owned subsidiary of BSMC as of December 31, 2013, to BSMC and the Partnership in exchange for common units representing a 1% limited partner interest in BSMC and common units representing a 1% limited partner interest in the Partnership;
- the merger of BSMC with and into a wholly owned subsidiary of the Partnership (the “Merger Sub”), with BSMC as the surviving entity, and immediately thereafter the Partnership will own a 99% limited partner interest in BSMC;
- in connection with the merger, (i) the redemption of the limited partner interest in the Partnership held by BSMC, (ii) the exchange of the common units and the preferred units of BSMC (other than those common units that of BSMC are held by BSNR) for an aggregate of   of the Partnership’s common units and   of the Partnership’s preferred units, respectively, (iii) the exchange of common units of BSMC held by BSNR for a 1% limited partner interest in BSMC, (iv) the non-economic general partner interest in the Partnership held by BSNR continuing to be outstanding, and (v) the conversion of the Partnership’s 100% equity interest in the Merger Sub into a 99% limited partner interest in BSMC and the non-economic general partner interest in BSMC held by BSNR continuing to be outstanding; and
- the issuance and sale of   common units by the Partnership to the public and the application of the net proceeds therefrom.

Upon completion of the Offering, the Partnership anticipates incurring incremental general and administrative expenses of approximately $ million as a result of being a publicly traded partnership, consisting of costs associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NYSE listing, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees and director and officer insurance and additional compensation. The pro forma financial statements do not reflect these incremental selling, general and administrative expenses.

BLACK STONE MINERALS, L.P.
UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET
June 30, 2014
(in thousands)

	Predecessor Historical	Pro Forma Adjustments	Pro Forma
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 12,789	$ (a)(b)	$
Accounts receivable	105,768	—	105,768
Prepaid expenses and other current assets	10,755	—	10,755
TOTAL CURRENT ASSETS	129,312		
PROPERTY AND EQUIPMENT			
Oil and natural gas properties on the basis of the successful efforts method of accounting, includes unproved properties of $662,528 at June 30, 2014	2,343,659	—	2,343,659
Less: Accumulated depreciation, depletion, and amortization	(1,012,364)	—	(1,012,364)
Oil and natural gas properties, net	1,331,295	—	1,331,295
Other property and equipment, net of accumulated depreciation and amortization of $11,941 at June 30, 2014	3,117	—	3,117
NET PROPERTY AND EQUIPMENT	1,334,412	—	1,334,412
DEFERRED CHARGES AND OTHER LONG TERM ASSETS	3,045	—	3,045
TOTAL ASSETS	$ 1,466,769	$	$

The accompanying notes to unaudited pro forma consolidated financial statements are an integral part of this statement.

BLACK STONE MINERALS, L.P.
UNAUDITED PRO FORMA CONSOLIDATED BALANCE SHEET
June 30, 2014
(in thousands)

	Predecessor Historical	Pro Forma Adjustments	Pro Forma
LIABILITIES, MEZZANINE EQUITY AND EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 36,328	$ —	$ 36,328
Accrued liabilities	12,009	—	12,009
Commodity derivative liabilities—current portion	6,834	—	6,834
Accrued partners' distribution payable—related party	52,570	—	52,570
TOTAL CURRENT LIABILITIES	107,741	—	107,741
LONG-TERM LIABILITIES			
Credit facilities	453,000	(453,000)(b)	—
Accrued incentive compensation—non-current portion	3,299	—	3,299
Commodity derivative liabilities—non-current portion	408	—	408
Deferred revenue	3,990	—	3,990
Asset retirement obligations	6,306	—	6,306
TOTAL LIABILITIES	574,744	(453,000)	121,744
COMMITMENTS AND CONTINGENCIES			
MEZZANINE EQUITY			
Partners' equity—redeemable preferred units, 157 units authorized and outstanding at June 30, 2014	161,122	—	161,122
EQUITY			
Partners' equity—common units, 2,219,488 units authorized, issued, and outstanding at June 30, 2014	726,958	(a)	
Noncontrolling interests	3,945	—	3,945
TOTAL EQUITY	730,903		
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$1,466,769	$	$

The accompanying notes to unaudited pro forma consolidated financial statements are an integral part of this statement.

BLACK STONE MINERALS, L.P.
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS
For the Six Months Ended June 30, 2014
(in thousands, except per unit amounts)

	Predecessor Historical	Pro Forma Adjustments	Pro Forma
REVENUE			
Oil and condensate sales	$ 124,576	$ —	$ 124,576
Natural gas and natural gas liquids sales	110,640	—	110,640
Loss on commodity derivative instruments	(8,343)	—	(8,343)
Lease bonus and other income	19,476	—	19,476
TOTAL REVENUE	246,349	—	246,349
OPERATING EXPENSES			
Lease operating expense and other	9,674	—	9,674
Production and ad valorem taxes	21,408	—	21,408
Depletion, depreciation, and amortization	46,993	—	46,993
General and administrative expense	29,963	—	29,963
Accretion of asset retirement obligations	295	—	295
TOTAL OPERATING EXPENSES	108,333	—	108,333
INCOME FROM OPERATIONS	138,016	—	138,016
OTHER INCOME (EXPENSE)			
Interest and investment income	24	—	24
Interest expense	(6,852)	5,017(c)(d)	(1,835)
Other income	807	—	807
TOTAL OTHER INCOME (EXPENSE)	(6,021)	5,017	(1,004)
NET INCOME	131,995	5,017	137,012
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(23)	—	(23)
NET INCOME ATTRIBUTABLE TO BLACK STONE MINERALS COMPANY, L.P.	131,972	5,017	136,989
LESS: DIVIDENDS ON PREFERRED UNITS	(7,801)	—	(7,801)
NET INCOME ATTRIBUTABLE TO COMMON UNITS	$ 124,171	$ 5,017	$ 129,188
EARNINGS PER UNIT (BASIC AND DILUTED)	$ 0.06		$
WEIGHTED AVERAGE UNITS OUTSTANDING (BASIC AND DILUTED)	2,130,140		

The accompanying notes to unaudited pro forma consolidated financial statements are an integral part of this statement.

Table of Contents

BLACK STONE MINERALS, L.P.
UNAUDITED PRO FORMA CONSOLIDATED STATEMENT OF OPERATIONS
For the Year Ended December 31, 2013
(in thousands, except per unit amounts)

	Predecessor Historical	Pro Forma Adjustments	Pro Forma
REVENUE			
Oil and condensate sales	$ 252,742	$ —	$252,742
Natural gas and natural gas liquids sales	184,868	—	184,868
Loss on commodity derivative instruments	(5,860)	—	(5,860)
Lease bonus and other income	31,809	—	31,809
TOTAL REVENUE	463,559	—	463,559
OPERATING EXPENSES			
Lease operating expense and other	21,316	—	21,316
Production and ad valorem taxes	42,813	—	42,813
Depletion, depreciation, and amortization	102,442	—	102,442
Impairment of oil and natural gas properties	57,109	—	57,109
General and administrative expense	59,501	—	59,501
Accretion of asset retirement obligations	588	—	588
TOTAL OPERATING EXPENSES	283,769	—	283,769
INCOME FROM OPERATIONS	179,790	—	179,790
OTHER INCOME (EXPENSE)			
Interest and investment income	90	—	90
Interest expense	(11,342)	7,709(c)(d)	(3,633)
Gain on sale of assets	18	—	18
Other income	407	—	407
TOTAL OTHER INCOME (EXPENSE)	(10,827)	7,709	(3,118)
NET INCOME	168,963	7,709	$176,672
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(373)	—	(373)
NET INCOME ATTRIBUTABLE TO BLACK STONE MINERALS COMPANY, L.P.	168,590	7,709	176,299
LESS: DIVIDENDS ON PREFERRED UNITS	(15,742)	—	(15,742)
NET INCOME ATTRIBUTABLE TO COMMON UNITS	$ 152,848	$ 7,709	$160,557
EARNINGS PER UNIT (BASIC AND DILUTED)	$ 0.07		$
WEIGHTED AVERAGE UNITS OUTSTANDING (BASIC AND DILUTED)	2,144,599		

The accompanying notes to unaudited pro forma consolidated financial statements are an integral part of this statement.

BLACK STONE MINERALS, L.P.
NOTES TO UNAUDITED PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Basis of Presentation

The unaudited pro forma balance sheet of the Partnership as of June 30, 2014, and the related unaudited pro forma statements of operations for the year ended December 31, 2013 and the six months ended June 30, 2014 are derived from the historical consolidated financial statements of the Predecessor.

Upon completion of this offering, the Partnership anticipates incurring incremental general and administrative expenses of approximately $ million as a result of being a publicly traded partnership, consisting of costs associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NYSE listing, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees, director and officer insurance, and additional compensation. The unaudited pro forma financial statements do not reflect these incremental general and administrative expenses.

The unaudited pro forma adjustments included herein assume no exercise of the underwriters' option to purchase additional common units. Any net proceeds received from the exercise of this option will be used to fund future capital expenditures.

Note 2—Unaudited Pro Forma Adjustments and Assumptions

A summary of the unaudited pro forma adjustments to effect the transactions is as follows:

(a) Reflects the issuance and sale of common units by the Partnership at an assumed initial public offering price of $ per common unit, net of an underwriting discount and offering expenses of million, and the receipt of the estimated net proceeds therefrom.

(b) Reflects the use of the net proceeds from the Offering to repay all of the debt outstanding under the credit facility with the remaining net proceeds reflected as an addition to cash.

(c) Reflects the elimination of interest expense after repayment of all of the debt outstanding under the credit facility discussed in (b) above.

(d) Reflects the commitment fee related to the credit facility of % on the $ borrowing base as well as the agency fees related to the credit facility. The fees were $ and $ for the year ended December 31, 2013 and the six months ended June 30, 2014, respectively.

Note 3—Unaudited Pro Forma Net Income Per Unit

Pro forma net income per unit is determined by dividing the pro forma net income available to common and preferred unitholders by the number of common units to be issued to the Predecessor's existing limited partners and the number of common units expected to be sold to the public in the Offering. For purposes of this calculation, the number of common units and preferred units outstanding at the closing of the Offering was assumed to be and , respectively. All units were assumed to have been outstanding since the beginning of the periods presented.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The General Partner of
Black Stone Minerals, L.P.

We have audited the accompanying balance sheet of Black Stone Minerals, L.P. (the “Partnership”) as of September 16, 2014. This balance sheet is the responsibility of the Partnership’s management. Our responsibility is to express an opinion on this balance sheet based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of the Partnership as of September 16, 2014 in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
October 7, 2014

BLACK STONE MINERALS, L.P.
BALANCE SHEET
As of September 16, 2014

ASSETS	
CURRENT ASSETS	
Cash and cash equivalents	$ —
TOTAL ASSETS	$ —
PARTNERS' CAPITAL	
Limited partner's capital	$ 100
General partner's capital	—
Subscription receivable	(100)
TOTAL PARTNERS' CAPITAL	$ —

The accompanying notes are an integral part of this financial statement.

BLACK STONE MINERALS, L.P.
NOTES TO BALANCE SHEET

Note 1—Organization

Black Stone Minerals, L.P. (the "Partnership") is a Delaware limited partnership formed on September 16, 2014. In connection with its formation, the Partnership issued a non-economic general partner interest in the Partnership to Black Stone Natural Resources, L.L.C. ("BSNR") and a 100% limited partner interest in the Partnership to Black Stone Minerals Company, L.P. ("BSMC"). The limited partner interest will be redeemed in connection with the merger of BSMC with and into a subsidiary of the Partnership, with BSMC as the surviving entity. In connection with the merger, the common units and preferred units of BSMC (other than those common units in BSMC held by BSNR) will be exchanged for common units and preferred units of the Partnership.

The accompanying balance sheet reflects the financial position of the Partnership. As of September 16, 2014, the $100 initial capitalization has not been funded. As a result, the Partnership has presented this as a subscription receivable.

Note 2—Subsequent Events

Subsequent events have been evaluated through the issuance date of the accompanying balance sheet of the Partnership. Any material subsequent events that occurred prior to such date have been properly recognized or disclosed in the balance sheet of the Partnership.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	June 30, 2014 (unaudited)	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 12,789	$ 30,123
Accounts receivable	105,768	91,092
Commodity derivative assets—current portion	—	38
Prepaid expenses and other current assets	10,755	4,510
TOTAL CURRENT ASSETS	129,312	125,763
PROPERTY AND EQUIPMENT		
Oil and natural gas properties on the basis of the successful efforts method of accounting, includes unproved properties of $662,528 and $640,291 at June 30, 2014 and December 31, 2013, respectively	2,343,659	2,277,514
Less: Accumulated depreciation, depletion, and amortization	(1,012,364)	(965,371)
Oil and natural gas properties, net	1,331,295	1,312,143
Other property and equipment, net of accumulated depreciation and amortization of $11,941 and $10,940 at June 30, 2014 and December 31, 2013, respectively	3,117	2,891
NET PROPERTY AND EQUIPMENT	1,334,412	1,315,034
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	3,045	3,616
TOTAL ASSETS	$ 1,466,769	$1,444,413

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	June 30, 2014 (unaudited)	December 31, 2013
LIABILITIES, MEZZANINE EQUITY AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 36,328	$ 30,722
Accrued liabilities	12,009	13,198
Commodity derivative liabilities—current portion	6,834	1,552
Accrued partners' distribution payable—related party	52,570	52,333
TOTAL CURRENT LIABILITIES	107,741	97,805
LONG-TERM LIABILITIES		
Credit facilities	453,000	451,000
Accrued incentive compensation—non-current portion	3,299	2,374
Commodity derivative liabilities—non-current portion	408	315
Deferred revenue	3,990	9,163
Asset retirement obligations	6,306	5,961
TOTAL LIABILITIES	574,744	566,618
COMMITMENTS AND CONTINGENCIES (Note 7)		
MEZZANINE EQUITY		
Partners' equity—redeemable preferred units, 157 units authorized, issued, and outstanding at June 30, 2014 and December 31, 2013	161,122	161,392
EQUITY		
Partners' equity—common units, 2,129,488 units and 2,124,944 units authorized, issued, and outstanding at June 30, 2014 and December 31, 2013, respectively	726,958	712,313
Noncontrolling interests	3,945	4,090
TOTAL EQUITY	730,903	716,403
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 1,466,769	$ 1,444,413

The accompanying notes to consolidated financial statements are an integral part of this statement.

Table of Contents

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(unaudited)	
REVENUE		
Oil and condensate sales	$ 124,576	$ 118,615
Natural gas and natural gas liquids sales	110,640	95,335
Gain (loss) on commodity derivative instruments	(8,343)	1,522
Lease bonus and other income	19,476	7,155
TOTAL REVENUE	246,349	222,627
OPERATING EXPENSES		
Lease operating expense and other	9,674	10,347
Production and ad valorem taxes	21,408	19,340
Depreciation, depletion and amortization	46,993	51,090
Impairment of oil and natural gas properties	—	27,630
General and administrative expense	29,963	28,940
Accretion of asset retirement obligations	295	307
TOTAL OPERATING EXPENSES	108,333	137,654
INCOME FROM OPERATIONS	138,016	84,973
OTHER INCOME (EXPENSE)		
Interest and investment income	24	65
Interest expense	(6,852)	(4,747)
Gain on sale of assets	—	18
Other income	807	137
TOTAL OTHER INCOME (EXPENSE)	(6,021)	(4,527)
NET INCOME	131,995	80,446
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(23)	(307)
NET INCOME ATTRIBUTABLE TO BLACK STONE MINERALS COMPANY, L.P.	131,972	80,139
LESS: DIVIDENDS ON PREFERRED UNITS	(7,801)	(7,807)
NET INCOME ATTRIBUTABLE TO COMMON UNITS	$ 124,171	$ 72,332
EARNINGS PER UNIT (BASIC AND DILUTED)	$ 0.06	$ 0.03
WEIGHTED AVERAGE UNITS OUTSTANDING (BASIC AND DILUTED)	2,130,140	2,150,131

The accompanying notes to consolidated financial statements are an integral part of this statement.

Table of Contents

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
(unaudited)
(in thousands)

	Class A common units	Class B common units	Partners' equity—common units	Noncontrolling interests	Total
BALANCE AT DECEMBER 31, 2013	1,172,174	952,770	$ 712,313	4,090	$ 716,403
Conversion of preferred units	—	201	221	—	221
Contributions—property	—	1,340	2,258	—	2,258
Repurchases of common units	(2,618)	(476)	(5,199)	—	(5,199)
Restricted common units granted, net of forfeitures	6,097	—	—	—	—
Equity-based compensation	—	—	6,754	—	6,754
Distributions	—	—	(112,460)	(168)	(112,628)
Net income	—	—	130,872	23	130,895
Dividends on preferred units	—	—	(7,801)	—	(7,801)
BALANCE AT JUNE 30, 2014	1,175,653	953,835	$ 726,958	3,945	$ 730,903

The accompanying notes to consolidated financial statements are an integral part of this statement.

Table of Contents

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$131,995	$ 80,446
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization	46,993	51,090
Impairment of oil and natural gas properties	—	27,630
Accretion of asset retirement obligations	295	307
Amortization of debt issue costs	483	517
(Gain) loss on commodity derivative instruments	(8,343)	1,522
Net cash received (paid) on settlement of commodity instruments	13,743	(1,194)
Equity-based compensation	5,654	3,394
Gain on sale of assets	—	(18)
Changes in operating assets and liabilities:		
Accounts receivable	(14,282)	(13,622)
Prepaid expenses and other current assets	(6,246)	(2,317)
Accounts payable and accrued liabilities	(1,904)	(4,838)
Deferred revenue	(2,516)	—
Settlement of asset retirement obligations	(12)	(17)
NET CASH PROVIDED BY OPERATING ACTIVITIES	165,860	142,900
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to oil and natural gas properties	(30,198)	(42,443)
Purchase of other property and equipment	(226)	(325)
Proceeds from sales of assets	—	74
Acquisitions of oil and natural gas properties	(29,431)	(81,161)
NET CASH USED IN INVESTING ACTIVITIES	(59,855)	(123,855)

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

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(unaudited)	(unaudited)
CASH FLOWS FROM FINANCING ACTIVITIES		
Contributions from common equity owners	—	191,611
Distributions to common equity owners	(112,391)	(103,560)
Repurchase of common equity units	(5,199)	(50,176)
Preferred equity dividends	(7,850)	(7,839)
Repayments of revolving credit facilities	—	(46,100)
Borrowings (repayments) under senior line of credit	2,000	(3,000)
Note receivable—officers	101	—
Debt issue costs	—	(1,235)
Purchases of noncontrolling interests	—	(24,142)
NET CASH USED IN FINANCING ACTIVITIES	(123,339)	(44,441)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(17,334)	(25,396)
CASH AND CASH EQUIVALENTS—beginning of the period	30,123	47,301
CASH AND CASH EQUIVALENTS—end of the period	$ 12,789	$ 21,905
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 6,480	$ 4,203
NON-CASH ACTIVITIES		
Property additions financed through accounts payable and accrued liabilities	$ 22,784	$ 20,561
Acquisitions of oil and natural gas properties financed through issuance of common units of noncontrolling interests	$ 2,258	$ 227,119
Distributions—property	$ —	$ 19,029
Accrued repurchases of common units	$ —	$ 47,095
Contributions through exchanges	$ —	$1,019,340
Conversion of preferred equity	$ (221)	$ —
Deferred revenue used as consideration for oil and natural gas property acquired	$ 2,657	$ —

The accompanying notes to consolidated financial statements are an integral part of this statement.

**BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)**

NOTE 1—BUSINESS AND BASIS OF PRESENTATION

Description of the Business: Black Stone Minerals Company, L.P., a Delaware limited partnership, and its subsidiaries (collectively referred to as "BSMC" or the "Company") own oil and natural gas mineral interests in the United States. In addition to mineral interests, the Company's assets include nonparticipating royalty interests and overriding royalty interests. These non-cost-bearing interests are collectively referred to as "mineral and royalty interests". The Company's mineral and royalty interests are located in most of the major onshore oil and natural gas producing basins spread across 41 states and 6 onshore oil and natural gas producing basins of the continental United States ("U.S."). The Company also owns non-operated working interests primarily related to its mineral interests.

For the years ended December 31, 2013 and 2012, Black Stone Natural Resources, L.L.C., a Delaware limited liability company ("BSNR"), was the 1% general partner of BSMC. Effective December 31, 2013, BSMC acquired all shares of BSNR, and BSNR became a wholly owned subsidiary of BSMC. BSNR and BSMC have common ownership and management. This transaction was accounted for as a transaction under common control. The change in the reporting entity has been retrospectively reflected; however, there is no impact on the consolidated financial statements of the Company.

Basis of Presentation: The accompanying financial statements of the Company have been prepared in accordance with generally accepted accounting principles ("GAAP") in the U.S and pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). Certain information and note disclosures commonly included in annual financial statements have been omitted pursuant to the rules and regulations of the SEC. Accordingly, the accompanying financial statements and notes should be read in conjunction with the Company's annual consolidated financial statements and notes to consolidated financial statements. 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 Company evaluates significant terms of its investments to determine the method of accounting applied to the investments. Investments in which the Company has less than a 20% ownership interest and does not have control or exercise significant influence are accounted for under the cost method. The Company's cost method investments are included in deferred charges and other long-term assets in the consolidated balance sheets. The Company does not have any equity method investments as of December 31, 2013. Investments in which the Company exercises control are consolidated, and the noncontrolling interests of such investments, which are not attributable directly or indirectly to the Company, are presented as a separate component of net income and equity in the accompanying consolidated financial statements.

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

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

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant Accounting Policies: Our significant accounting policies are discussed in the financial statements for the years ended December 31, 2013 and 2012. There have been no changes in such policies or application of such policies during the six month period ended June 30, 2014.

New Accounting Pronouncements: In April 2014, the Financial Accounting Standards Board ("FASB") issued accounting standards updates to Accounting Standard Codification ("ASC") 205, *Presentation of Financial Statements*, and to ASC 360, *Property, Plant, and Equipment*, to change the criteria for reporting discontinued operations. The amendments modify the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have or will have a major effect on an entity's operations and financial results. These amendments require additional disclosures about discontinued operations and new disclosures for other disposals of individually material components of an organization that do not meet the definition of a discontinued operation. In addition, the guidance allows companies to have significant continuing involvement and continuing cash flows with the discontinued operation. These provisions are effective for public companies prospectively for annual reporting periods beginning on or after December 15, 2014, and interim periods within those annual periods, with early adoption permitted. The adoption of this guidance, effective January 1, 2015, will not affect the Company's consolidated financial position or results of operations; however, it may result in changes to the manner in which future dispositions of operations or assets, if any, are presented in the Company's financial statements, or it may require additional disclosures.

In May 2014, the FASB issued an accounting standards update on a comprehensive new revenue recognition standard that will supersede the existing revenue recognition guidance. The new accounting guidance creates a framework under which an entity will allocate the transaction price to separate performance obligations and recognize revenue when each performance obligation is satisfied. Under the new standard, entities will be required to use judgment and make estimates, including identifying performance obligations in a contract, estimating the amount of variable consideration to include in the transaction price, allocating the transaction price to each separate performance obligation and determining when an entity satisfies its performance obligations. The standard allows for either "full retrospective" adoption, meaning that the standard is applied to all of the periods presented with a cumulative catch-up as of the earliest period presented, or "modified retrospective" adoption, meaning the standard is applied only to the most current period presented in the financial statements with a cumulative catch-up as of the current period. The accounting standard will be effective for reporting periods beginning after December 15, 2016 for public companies. The Company is in the process of evaluating the impact that the new accounting guidance will have on its consolidated financial position, results of operations, and cash flows.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 3—ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations ("AROs") consist primarily of estimated costs of dismantlement, removal, site reclamation, and similar activities associated with oil and natural gas properties. Changes in AROs during the periods presented are as follows:

	June 30, 2014	December 31, 2013
	(in thousands)	
Beginning asset retirement obligations	$5,961	$ 5,242
Liabilities incurred	62	164
Liabilities settled	(12)	(33)
Accretion expense	295	588
Ending asset retirement obligations	$6,306	$ 5,961

NOTE 4—DERIVATIVES AND FINANCIAL INSTRUMENTS

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

With a costless collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the exercise price of the purchased put. The Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the exercise price for the sold call of the collar. The settlement paid or received is the difference between the market price on the settlement date and the related exercise price. All derivative instruments are reflected as either assets or liabilities in the Company's accompanying consolidated balance sheet as of December 31, 2013 and 2012, respectively. See Note 5 for further discussion of fair value. The table below summarizes the fair value and classification of the Company's derivative instruments:

As of June 30, 2014
(in thousands)

Classification	Balance Sheet Location	Gross Fair Value	Effect of Counter-party Netting	Net Carrying Value on Balance Sheet
Assets:				
Current asset	Commodity derivative asset	$ 1,700	$ (1,700)	$ —
Non-current asset	Deferred charges and other long-term assets	978	(948)	30
Total assets		$ 2,678	$ (2,648)	$ 30
Liabilities:				
Current liability	Commodity derivative liability	$ 8,484	$ (1,650)	$ 6,834
Non-current liability	Commodity derivative liability	1,406	(998)	408
Total liabilities		$ 9,890	$ (2,648)	$ 7,242

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

		As of December 31, 2013 (in thousands)		
Classification	**Balance Sheet Location**	**Gross Fair Value**	**Effect of Counter-party Netting**	**Net Carrying Value on Balance Sheet**
Assets:				
Current asset	Commodity derivative asset	$ 2,888	$ (2,850)	$ 38
Non-current asset	Deferred charges and other long-term assets	1,521	(1,504)	17
Total assets		$ 4,409	$ (4,354)	$ 55
Liabilities:				
Current liability	Commodity derivative liability	$ 4,397	$ (2,845)	$ 1,552
Non-current liability	Commodity derivative liability	1,824	(1,509)	315
Total liabilities		$ 6,221	$ (4,354)	$ 1,867

Changes in the fair values of the Company's derivative instruments (both assets and liabilities) are presented on a net basis in the accompanying consolidated statements of operations. The following table details the unrealized and realized gains (losses) recognized from the Company's derivative instruments and where these components are recorded on the Company's accompanying consolidated statements of operations for the six months ended June 30, 2014 and 2013:

Derivatives not designated as hedging instruments under ASC 815	**Location of Gain (Loss)**	**Classification of Gain (Loss)**	**Six Months Ended June 30, 2014**	**Six Months Ended June 30, 2013**
			(in thousands)	
Oil commodity contracts	Gain (loss) on commodity derivative instruments	Realized	$ (273)	$ 346
Gas commodity contracts	Gain (loss) on commodity derivative instruments	Realized	(2,670)	1,504
Total realized gains (losses) from derivatives not designated as hedges			$ (2,943)	$ 1,850
Oil commodity contracts	Gain (loss) on commodity derivative instruments	Unrealized	$ (6,183)	$ (134)
Gas commodity contracts	Gain (loss) on commodity derivative instruments	Unrealized	783	(194)
Total unrealized losses from derivatives not designated as hedges			$ (5,400)	$ (328)

The Company had the following open derivative contracts for crude oil at June 30, 2014:

Period and Type of Contract	**Volume in bbl**	**Weighted Average**	**Range Low**	**Range High**
2014				
Collar contracts:				
Call Options	848,000	$100.84	$100.00	$104.00
Put Options	848,000	$ 82.66	$ 80.00	$ 94.00
2015				
Collar contracts:				
Call Options	839,000	$101.64	$ 99.05	$104.00
Put Options	839,000	$ 84.03	$ 80.00	$ 90.00

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

The Company had the following open derivative contracts for natural gas at June 30, 2014:

Period and Type of Contract	Volume in MMBtu	Weighted Average	Range	
			Low	High
2014				
Collar contracts:				
Call Options	14,622,651	$ 4.90	$4.45	$5.40
Put Options	14,622,651	$ 3.73	$3.40	$4.50
2015				
Collar contracts:				
Call Options	8,870,000	$ 4.96	$4.60	$5.60
Put Options	8,870,000	$ 3.76	$3.50	$4.50

NOTE 5—FAIR VALUE DISCLOSURE

ASC 820, *Fair Value Measurement*, defines fair value as the amount at which an asset (or liability) could be bought (or incurred) or sold (or settled) in a current transaction between willing parties other than in a forced or liquidation sale. 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—Quoted prices (unadjusted) for identical assets or liabilities in active markets.

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. There were no transfers into, or out of, the three levels of the fair value hierarchy for the six months ended June 30, 2014 or the year ended December 31, 2013.

The Company estimated the fair value of derivative instruments using the market approach via a model that uses inputs that are observable in the market or can be derived from, or corroborated by, observable data (see Note 4 for further discussion on derivatives and financial instruments).

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

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

	Level 1	Level 2	Level 3	Effect of Netting	Total
			(in thousands)		
At June 30, 2014:					
Financial Assets					
Commodity derivative instruments	$ —	$2,678	$ —	$(2,648)	$ 30
Financial Liabilities					
Commodity derivative instruments	—	9,890	—	(2,648)	$7,242
At December 31, 2013:					
Financial Assets					
Commodity derivative instruments	$ —	$4,409	$ —	$(4,354)	$ 55
Financial Liabilities					
Commodity derivative instruments	—	6,221	—	(4,354)	1,867

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

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach. Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. Significant Level 3 assumptions used to determine fair value include estimates of proved reserves, future commodity prices, the timing and amount of future production and capital expenditures, and a discount rate commensurate with the risk associated with the respective oil and natural gas properties.

The Company's estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation techniques or related inputs for the six months ended June 30, 2014 or the year ended December 31, 2013.

NOTE 6—RELATED PARTY TRANSACTIONS

The Company executed promissory notes dated April 15, 2010 in the amount of $0.5 million to officers of the Company. The promissory notes related to the acquisition of a partnership interest in Ivory Acquisitions Partners, L.P. by the officers, and the notes were collateralized by a security interest in the Company. The promissory notes provided for quarterly payments of interest equaling the rate at which the Company paid interest on its borrowings. At December 31, 2013, the aggregated note balance was $0.1 million with less than $0.1 million of accrued interest income, which are both included in current assets on the consolidated balance sheets. For the year ended December 31, 2013, the promissory notes had a weighted average interest rate of 2.73%. These promissory notes were paid in full by the maturity date in April 2014.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

NOTE 7—COMMITMENTS AND CONTINGENCIES

Environmental Matters

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

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

Litigation

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

NOTE 8—EARNINGS PER UNIT

Class A common units and Class B common units have been combined as a single class for purposes of basic and diluted earnings per unit ("EPU") as they contain the same economic rights and preferences. The holders of the Company's restricted common units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common units are included in the calculation of basic earnings per unit using the two-class method. For the periods presented, the amount of earnings allocated to the participating restricted common units was not material. The redeemable Preferred Units can be converted into 142.6 million and 142.8 million common units as of June 30, 2014 and 2013, respectively. At June 30, 2014 and 2013, if the redeemable Preferred Units were converted to common units, their effect would be anti-dilutive; therefore, the redeemable Preferred Units are not included in the diluted EPU calculation.

The following table sets forth the computation of basic and diluted earnings per unit (in thousands, except per unit amounts):

	Six Months Ended June 30,	
	2014	2013
	(in thousands)	
Net income	$ 131,995	$ 80,446
Less: Net income attributable to noncontrolling interests	(23)	(307)
Net income attributable to Black Stone Minerals Company, L.P.	131,972	80,139
Less: Dividends on preferred units	(7,801)	(7,807)
Net income available to common units	$ 124,171	$ 72,332
Weighted average units outstanding (basic and diluted)	2,130,140	2,150,131
Basic and diluted earnings per unit	$ 0.06	$ 0.03

NOTE 9—SUBSEQUENT EVENTS

On July 15, 2014, the Company paid distributions of approximately $56.3 million to the holders of BSMC's common units and approximately $3.9 million to the owners of the Preferred Units.

On July 17, 2014, the Company acquired producing properties and leasehold interests in Reagan and Upton Counties, Texas, for $12.5 million.

REPORT OF INDEPENDENT REGISTERED ACCOUNTING FIRM

The General Partner of
Black Stone Minerals Company, L.P.

We have audited the accompanying consolidated balance sheets of Black Stone Minerals Company, L.P. and Subsidiaries (collectively referred to as the "Company"), as of December 31, 2013 and 2012, and the related consolidated statements of operations, equity, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2013 and 2012, and the consolidated results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas
October 7, 2014

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	As of December 31, 2013	As of December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 30,123	$ 47,301
Accounts receivable	91,092	68,869
Commodity derivative assets—current portion	38	5,212
Prepaid expenses and other current assets	4,510	3,254
TOTAL CURRENT ASSETS	125,763	124,636
PROPERTY AND EQUIPMENT		
Oil and natural gas properties on the basis of the successful efforts method of accounting, includes unproved properties of $640,291 and $369,071 at December 31, 2013 and 2012, respectively	2,277,514	1,884,919
Less: Accumulated depreciation, depletion and amortization	(965,371)	(817,950)
Oil and natural gas properties, net	1,312,143	1,066,969
Other property and equipment, net of accumulated depreciation and amortization of $10,940 and $9,121 at December 31, 2013 and 2012, respectively	2,891	4,217
NET PROPERTY AND EQUIPMENT	1,315,034	1,071,186
DEFERRED CHARGES AND OTHER LONG-TERM ASSETS	3,616	3,365
TOTAL ASSETS	$1,444,413	$1,199,187

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)

	As of December 31, 2013	As of December 31, 2012
LIABILITIES, MEZZANINE EQUITY AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 30,722	$ 34,202
Accrued liabilities	13,198	13,447
Commodity derivative liabilities—current portion	1,552	—
Credit facilities—current portion	—	19,100
Accrued fund repurchases	—	23,319
Accrued partners' distribution payable—related party	52,333	42,950
TOTAL CURRENT LIABILITIES	97,805	133,018
LONG-TERM LIABILITIES		
Credit facilities—non-current portion	451,000	344,000
Accrued incentive compensation—non-current portion	2,374	—
Commodity derivative liabilities—non-current portion	315	—
Deferred partner contributions	—	220,622
Deferred revenue	9,163	8,261
Asset retirement obligations	5,961	5,242
TOTAL LIABILITIES	566,618	711,143
COMMITMENTS AND CONTINGENCIES (Note 13)		
MEZZANINE EQUITY		
Partners' equity—redeemable preferred units, 157 units authorized, issued, and outstanding at December 31, 2013 and 2012	161,392	161,381
EQUITY		
Partners' equity (deficit)—common units, 2,124,944 and 1,210,473 units authorized, issued, and outstanding at December 31, 2013 and 2012, respectively	712,313	(1,158)
Noncontrolling interests	4,090	327,821
TOTAL EQUITY	716,403	326,663
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$1,444,413	$1,199,187

The accompanying notes to consolidated financial statements are an integral part of this statement.

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

	Year Ended December 31, 2013	Year Ended December 31, 2012
REVENUE		
Oil and condensate sales	$ 252,742	$ 202,104
Natural gas and natural gas liquids sales	184,868	166,849
Gain (loss) on commodity derivative instruments	(5,860)	12,275
Lease bonus and other income	31,809	53,918
TOTAL REVENUE	463,559	435,146
OPERATING EXPENSES		
Lease operating expense and other	21,316	20,527
Production and ad valorem taxes	42,813	36,680
Depreciation, depletion and amortization	102,442	104,059
Impairment of oil and natural gas properties	57,109	62,987
General and administrative expense	59,501	50,348
Accretion of asset retirement obligations	588	608
TOTAL OPERATING EXPENSES	283,769	275,209
INCOME FROM OPERATIONS	179,790	159,937
OTHER INCOME (EXPENSE)		
Interest and investment income	90	209
Interest expense	(11,342)	(9,166)
Gain on sale of assets	18	363
Other income	407	467
TOTAL OTHER INCOME (EXPENSE)	(10,827)	(8,127)
NET INCOME	168,963	151,810
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(373)	(44,343)
NET INCOME ATTRIBUTABLE TO BLACK STONE MINERALS COMPANY, L.P.	168,590	107,467
LESS: DIVIDENDS ON PREFERRED UNITS	(15,742)	(15,742)
NET INCOME ATTRIBUTABLE TO COMMON UNITS	$ 152,848	$ 91,725
EARNINGS PER UNIT (BASIC AND DILUTED)	$ 0.07	$ 0.08
WEIGHTED AVERAGE UNITS OUTSTANDING (BASIC AND DILUTED)	2,144,599	1,212,885

The accompanying notes to consolidated financial statements are an integral part of this statement.

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

	Class A common units	Class B common units	Partners' equity—common units	Noncontrolling interests	Total
BALANCE AT DECEMBER 31, 2011	1,209,296	—	$ 147,387	510,351	$ 657,738
Repurchases of common units	(4,651)	—	(9,052)	—	(9,052)
Restricted common units granted, net of forfeitures	5,828	—	—	—	—
Equity-based compensation	—	—	7,247	—	7,247
Payments under promissory notes	—	—	118	—	118
Distributions	—	—	(119,996)	(122,599)	(242,595)
Purchases of noncontrolling interests	—	—	(118,587)	(104,274)	(222,861)
Net income	—	—	107,467	44,343	151,810
Dividends on preferred units	—	—	(15,742)	—	(15,742)
BALANCE AT DECEMBER 31, 2012	1,210,473	—	$ (1,158)	327,821	$ 326,663
Contributions—cash	—	243,411	412,233	—	412,233
Contributions—limited partner interests	1,306	600,456	1,019,340	—	1,019,340
Contributions—property	—	134,107	227,119	—	227,119
Repurchases of common units	(44,834)	(25,204)	(118,108)	—	(118,108)
Restricted common units granted, net of forfeitures	5,229	—	—	—	—
Equity-based compensation	—	—	6,782	—	6,782
Distributions	—	—	(234,311)	(767)	(235,078)
Distributions—property	—	—	—	(19,029)	(19,029)
Purchases of noncontrolling interests	—	—	(22,696)	(14,704)	(37,400)
Exchange of noncontrolling interests	—	—	(729,736)	(289,604)	(1,019,340)
Net income	—	—	168,590	373	168,963
Dividends on preferred units	—	—	(15,742)	—	(15,742)
BALANCE AT DECEMBER 31, 2013	1,172,174	952,770	$ 712,313	4,090	$ 716,403

The accompanying notes to consolidated financial statements are an integral part of this statement.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOW
(in thousands)

	Year Ended December 31,	
	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 168,963	$ 151,810
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization	102,442	104,059
Impairment of oil and natural gas properties	57,109	62,987
Accretion of asset retirement obligations	588	608
Amortization of debt issue costs	968	655
Gain (loss) on commodity derivative instruments	(5,860)	12,275
Net cash received (paid) on settlement of commodity instruments	13,210	(1,578)
Equity-based compensation	6,782	7,247
Gain on sale of assets	(18)	(363)
Changes in operating assets and liabilities:		
Accounts receivable	(15,046)	13,535
Prepaid expenses and other current assets	(1,256)	(617)
Accounts payable and accrued liabilities	(7,085)	(466)
Deferred revenue	—	7,881
Settlement of asset retirement obligations	(33)	(31)
NET CASH PROVIDED BY OPERATING ACTIVITIES	320,764	358,002
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to oil and natural gas properties	(73,650)	(89,291)
Purchase of other property and equipment	(493)	(330)
Proceeds from sales of assets	74	1,048
Acquisitions of oil and natural gas properties	(121,562)	(110,402)
NET CASH USED IN INVESTING ACTIVITIES	(195,631)	(198,975)

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOW
(in thousands)

	Year Ended December 31,	
	2013	2012
CASH FLOWS FROM FINANCING ACTIVITIES		
Contributions from common equity partners	191,611	220,622
Repayments of promissory notes	—	118
Distributions to common equity owners	(225,704)	(222,815)
Repurchase of common equity units	(118,108)	(9,052)
Preferred equity dividends	(15,732)	(15,753)
Repayments of revolving credit facilities	(46,100)	—
Borrowings under senior line of credit	134,000	90,350
Note receivable—officers	101	152
Debt issue costs	(1,660)	(2,252)
Purchase of noncontrolling interests	(60,719)	(199,542)
NET CASH USED IN FINANCING ACTIVITIES	(142,311)	(138,172)
NET CHANGE IN CASH AND CASH EQUIVALENTS	(17,178)	20,855
CASH AND CASH EQUIVALENTS—beginning of the year	47,301	26,446
CASH AND CASH EQUIVALENTS—end of the year	$ 30,123	$ 47,301
SUPPLEMENTAL DISCLOSURE		
Interest paid	$ 10,344	$ 8,351
NON-CASH ACTIVITIES		
Property additions financed through accounts payable and accrued liabilities	$ 23,029	$ 16,210
Acquisition of oil and natural gas properties through exchanges	$ 227,119	$ —
Contributions through exchange of noncontrolling interests	$1,019,340	$ —
Accrued repurchases of noncontrolling interests	$ —	$ 23,319
Distributions—property	$ 19,029	$ —
Accrued distribution payable	$ 9,374	$ 19,780

The accompanying notes to consolidated financial statements are an integral part of this statement.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—BUSINESS AND BASIS OF PRESENTATION

Description of the Business: Black Stone Minerals Company, L.P., a Delaware limited partnership, and its subsidiaries (collectively referred to as "BSMC" or the "Company") own oil and natural gas mineral interests in the United States. In addition to mineral interests, the Company's assets include nonparticipating royalty interests and overriding royalty interests. These non-cost-bearing interests are collectively referred to as "mineral and royalty interests". The Company's mineral and royalty interests are located in most of the major onshore oil and natural gas producing basins spread across 41 states and 66 onshore oil and natural gas producing basins of the continental United States ("U.S."). The Company also owns non-operated working interests.

For the years ended December 31, 2013 and 2012, Black Stone Natural Resources, L.L.C., a Delaware limited liability company ("BSNR"), was the 1% general partner of BSMC. Effective December 31, 2013, BSMC acquired all shares of BSNR, and BSNR became a wholly owned subsidiary of BSMC. BSNR and BSMC have common ownership and management. This transaction was accounted for as a transaction under common control. The change in the reporting entity has been retrospectively reflected; however, there is no impact on the consolidated financial statements of the Company.

Basis of Presentation: The accompanying financial statements of the Company have been prepared in accordance with generally accepted accounting principles ("GAAP") in the U.S. The financial statements include the consolidated results of the Company. All intercompany balances and transactions have been eliminated.

The Company evaluates significant terms of its investments to determine the method of accounting applied to the investments. Investments in which the Company has less than a 20% ownership interest and does not have control or exercise significant influence are accounted for under the cost method. The Company's cost method investments are included in deferred charges and other long-term assets in the consolidated balance sheets. The Company does not have any equity method investments as of December 31, 2013 and 2012. Investments in which the Company exercises control are consolidated, and the noncontrolling interests of such investments, which are not attributable directly or indirectly to the Company, are presented as a separate component of net income and equity in the accompanying consolidated financial statements.

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

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

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates: The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

The Company's consolidated financial statements are based on a number of significant estimates including oil and natural gas reserve quantities that are the basis for the calculations of depreciation, depletion, and amortization ("DD&A") and impairment of oil and natural gas properties. Reservoir engineering is a subjective

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

process of estimating underground accumulations of oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered. The Company's reserve estimates are determined by an independent petroleum engineering firm. Other items subject to significant estimates and assumptions include the carrying amount of oil and natural gas properties and valuation of derivative instruments.

The Company evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions. A significant decline in natural gas prices or in oil prices could result in a reduction in the Company's fair value estimates and cause the Company to perform analyses to determine if its oil and natural gas properties are impaired. As future commodity prices cannot be determined accurately, actual results could differ significantly from estimates. See Supplemental Oil and Gas Information (Unaudited).

Cash and Cash Equivalents: The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Concentration of Credit Risk: Financial instruments that potentially subject the Company to credit risk consist principally of cash and cash equivalent balances, accounts receivable and derivative financial instruments. The Company maintains cash and cash equivalent balances with major financial institutions. At times, those balances exceed federally insured limits; however, no losses have been incurred. The Company attempts to limit the amount of credit exposure to any one company through procedures that include credit approvals, credit limits and terms, and prepayments. The Company's customer base is made up of its lessees, which are primarily major integrated and international oil and natural gas companies and other operators, though the Company's credit risk may extend to the eventual purchasers of oil and natural gas produced from the Company's properties. The Company believes the credit quality of its customer base is high and has not experienced significant write-offs in its accounts receivable balances. See Note 9—Significant Customers for further discussion.

Accounts Receivable: The Company's accounts receivable balance results primarily from operators' sales of oil and natural gas to their customers. Accounts receivable is recorded at the contractual amounts and do not bear interest. Any concentration of customers may impact the Company's overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions affecting the oil and natural gas industry.

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

In accordance with Accounting Standard Codification ("ASC") 815, Derivatives and Hedging, derivative instruments are initially recognized at fair value on the date on which a derivative contract is entered into and are subsequently remeasured at fair value. If a right of offset exists under master netting arrangements and certain other criteria are met, derivative assets and liabilities with the same counterparty are netted on the consolidated balance sheet. Gains and losses arising from changes in the fair value of derivatives are recognized on a net basis in the accompanying consolidated statements of operations within gain (loss) on commodity derivative instruments.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Although these derivative instruments may expose the Company to credit risk, the Company monitors the creditworthiness of its counterparties.

Oil and Natural Gas Properties: The Company follows the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire interests in oil and natural gas properties are capitalized. The cost of property acquisitions, successful exploratory wells, development costs and support equipment and facilities are capitalized when incurred. Other exploratory costs, including annual delay rentals and geological and geophysical costs, are charged to expense when incurred. Acquired mineral and royalty interests and working interests are recorded at cost at the time of acquisition.

The costs of unproved leaseholds and mineral interests are capitalized as unproved properties pending the results of exploration and leasing efforts. As unproved leaseholds are determined to be producing, the related costs are transferred to producing properties. The remaining net book values of unproved leaseholds associated with unsuccessful drilling activities or that have expired, are charged to exploration expense, which is included in lease operating expense and other in the consolidated statements of operations.

As exploration and development work progresses and the reserves on the Company's properties are proven, capitalized costs attributed to the properties are charged as an operating expense through DD&A. DD&A of proven oil and natural gas properties is calculated using the unit-of-production method based on estimates of proved producing oil and natural gas reserves on a field-by-field basis. DD&A expense related to the Company's producing oil and natural gas properties was $102.4 million and $104.1 million for the years ended December 31, 2013 and 2012, respectively.

The Company evaluates impairment of producing properties whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. See Note 5 for further discussion of impairment of oil and natural gas properties.

The cost of properties sold, or otherwise disposed of, and the related accumulated depreciation is removed from the accounts and any gains or losses are reflected in current operations.

Other Property and Equipment: Other property and equipment includes furniture, fixtures, office equipment, leasehold improvements, and computer software and are stated at cost. Depreciation and amortization are calculated using the straight-line method over the expected useful lives ranging from three to seven years. Depreciation and amortization expense totaled $1.8 million and $1.7 million for the years ended December 31, 2013 and 2012, respectively.

Repairs and Maintenance: The cost of normal maintenance and repairs is charged to expense as incurred. Material expenditures that increase the life of an asset are capitalized and depreciated over the shorter of the estimated remaining useful life of the asset or the term of the lease.

Debt Issue Costs: Debt issue costs consist of costs directly associated with obtaining credit with financial institutions. These costs have been capitalized and are generally amortized on a straight-line basis over the life of the credit agreement, which approximates the effective-interest method. Any unamortized debt issue costs are written off in the year when the associated debt instrument is terminated. Amortization expense for debt issue costs was $1.0 million and $0.7 million for the years ended December 31, 2013 and 2012, respectively, and is included in interest expense in the consolidated statements of operations.

Asset Retirement Obligations: Fair values of legal obligations to retire and remove long-lived assets are recorded when the obligation is incurred. When the liability is initially recorded, the Company capitalizes this cost by increasing the carrying amount of the related property and equipment. Over time, the liability is increased for the change in its present value, and the capitalized cost in property and equipment is depreciated over the useful life of the related asset or group of assets.

Revenue Recognition: The Company recognizes revenue when it is realized or realizable and earned. Revenues are considered realized or realizable and earned when: (i) persuasive evidence of an arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the seller's price to the buyer is fixed or determinable and (iv) collectability is reasonably assured.

The Company recognizes oil and natural gas revenue from its interests in producing wells when the associated production is sold. The volumes of natural gas sold may differ from the volumes to which the Company is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves net to the Company will not be sufficient to enable the under-produced owner to recoup its entitled share through production; however, such amounts are de minimis. Other sources of revenue received by the Company includes mineral lease bonuses, shut-in royalties, and delay rentals which are recognized as revenue when earned according to the terms of the respective agreements.

Income Taxes: The Company is organized as a pass-through entity for income tax purposes. As a result, the Company's unitholders are responsible for federal and state income taxes on their share of the Company's taxable income. The Company is subject to certain state-based taxes; however, those taxes are not material.

Limited partnerships that receive at least 90% of their gross income from designated passive sources, including royalties from mineral properties and other non-operated mineral interest income, and do not receive more than 10% of their income from operating an active trade or business, are generally exempt from the Texas margin tax as "passive entities". The Company believes that it meets the requirements for being considered a "passive entity" for Texas margin tax purposes and, therefore, it is exempt from the Texas margin tax. As a result, each unitholder that is considered a taxable entity under the Texas margin tax would generally be required to include its portion of the Company's revenues in its own Texas margin tax computation. The Texas Administrative Code provides such income is sourced according to the principal place of business of the Company, which would be the state of Texas.

Fair Value of Financial Instruments: The carrying values of the Company's current financial instruments, which include cash and cash equivalents, accounts receivable, accounts payable, and accrued liabilities, approximate their fair value at December 31, 2013 and 2012 because of the short-term maturity of these instruments. For non-current financial instruments, the Company uses quoted market prices or, to the extent that there are no available quoted market prices, market prices for similar instruments. For long-term debt, since the interest rate is variable and aligns with market rates, the carrying value of debt approximates fair value. See Note 7 for further discussion on the fair value of the Company's financial instruments.

Incentive Compensation: Incentive compensation includes both equity-based awards and liability awards. The Company recognizes compensation expense associated with its equity-based compensation awards granted on a straight-line basis over the requisite service period (generally the vesting period of the awards) based on their fair values on the dates of grant in general and administrative expense.

Liability awards are awards that are expected to be settled in cash on their vesting dates. Liability awards are recorded as accrued liabilities based on the vested portion of the estimated fair value of the awards as of the grant date, which is subject to revision based on the impact of certain performance conditions associated with its incentive plans. The Company may also recognize liability awards as a result of repurchase options given to the recipients of certain incentive plans.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Subsequent Events: Subsequent events have been evaluated through the issuance date of these financial statements. Any material subsequent events that occurred prior to such date have been properly recognized or disclosed in the consolidated financial statements. See Note 18—Subsequent Events.

New Accounting Pronouncements: In April 2014, the Financial Accounting Standards Board ("FASB") issued accounting standards updates to ASC 205, *Presentation of Financial Statements*, and to ASC 360, *Property, Plant, and Equipment*, to change the criteria for reporting discontinued operations. The amendments modify the definition of discontinued operations by limiting discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have or will have a major effect on an entity's operations and financial results. These amendments require additional disclosures about discontinued operations and new disclosures for other disposals of individually material components of an organization that do not meet the definition of a discontinued operation. In addition, the guidance allows companies to have significant continuing involvement and continuing cash flows with the discontinued operation. These provisions are effective for public companies prospectively for annual reporting periods beginning on or after December 15, 2014, and interim periods within those annual periods, with early adoption permitted. The adoption of this guidance, effective January 1, 2015, will not affect the Company's consolidated financial position or results of operations; however, it may result in changes to the manner in which future dispositions of operations or assets, if any, are presented in the Company's financial statements, or it may require additional disclosures.

In May 2014, the FASB issued an accounting standards update on a comprehensive new revenue recognition standard that will supersede the existing revenue recognition guidance. The new accounting guidance creates a framework under which an entity will allocate the transaction price to separate performance obligations and recognize revenue when each performance obligation is satisfied. Under the new standard, entities will be required to use judgment and make estimates, including identifying performance obligations in a contract, estimating the amount of variable consideration to include in the transaction price, allocating the transaction price to each separate performance obligation and determining when an entity satisfies its performance obligations. The standard allows for either "full retrospective" adoption, meaning that the standard is applied to all of the periods presented with a cumulative catch-up as of the earliest period presented, or "modified retrospective" adoption, meaning the standard is applied only to the most current period presented in the financial statements with a cumulative catch-up as of the current period. The accounting standard will be effective for reporting periods beginning after December 15, 2016 for public companies. The Company is in the process of evaluating the impact that the new accounting guidance will have on its consolidated financial position, results of operations, and cash flows.

NOTE 3—ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations ("AROs") consist primarily of estimated costs of dismantlement, removal, site reclamation, and similar activities associated with oil and natural gas properties. Changes in AROs during the years presented are as follows:

	As of December 31,	
	2013	2012
	(in thousands)	
Beginning asset retirement obligations	$5,242	$4,466
Liabilities incurred	164	199
Liabilities settled	(33)	(31)
Accretion expense	588	608
Ending asset retirement obligations	$5,961	$5,242

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 4—ACQUISITION

Acquisitions of producing oil and natural gas properties are recorded at their estimated fair value as of the acquisition date.

In 2004, the Company and third-party investors acquired an interest in the producing and non-producing oil and natural gas properties of Pure Partners, L.P. and Pure Resources, L.P. ("Pure"). As of January 1, 2012, the Company owned 80.7% of the oil and natural gas properties of Pure. Third-party investors owned the remaining 19.3% of the oil and natural gas properties. Effective December 31, 2012 and January 1, 2013, the Company purchased the remaining ownership interest in the Pure oil and natural gas properties for $323.0 million, which consisted of $95.9 million of cash paid on December 31, 2012 and the issuance of $227.1 million of common units of BSMC on January 1, 2013.

The fair value of the assets acquired was determined based on discounted cash flows, including assumptions as to the estimated ultimate recovery of oil and natural gas reserves, expectations for timing of future development and operating costs, and risk adjusted discount rates. The following table summarizes the fair values assigned to the assets acquired as of the Pure acquisition dates:

	(in thousands)
Proved oil and natural gas properties	$ 73,352
Unproved oil and natural gas properties	240,579
Net working capital	9,088
Total net assets acquired	$ 323,019

Summarized below are the consolidated results of operations of the Company for the year ended December 31, 2012, on an unaudited pro forma basis, as if the entire Pure acquisition had occurred on January 1, 2012.

	Year Ended December 31, 2012	
	Actual	Pro Forma
	(unaudited) (in thousands)	
Revenue	$ 435,146	$ 458,842
Net income attributable to common units	91,725	113,792
Net income per common unit (basic and diluted)	$ 0.08	$ 0.08

NOTE 5—IMPAIRMENT OF OIL AND NATURAL GAS PROPERTIES

The Company evaluates the impairment of its proved oil and natural gas properties on a field-by-field basis at least annually or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

The Company compares the undiscounted projected future cash flows expected in connection with the field to the carrying amount to determine recoverability. When the carrying amount of a field 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 proved reserves, future commodity prices, timing, future production, future capital expenditures, and a risk-adjusted discount rate.

Impairment of proved oil and natural gas properties was $57.1 million and $63.0 million for the years ended December 31, 2013 and 2012, respectively. The impairment primarily resulted from decreasing commodity

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

prices in certain regions and changes in the projections based on the recent historical operating characteristics at the field level. The charges are included in impairment of oil and natural gas properties on the consolidated statements of operations.

The carrying value of unproved properties, including unleased mineral rights, is periodically assessed for impairment via comparison to management's assessment of value. The factors used to determine fair value are similar to those noted previously for proved properties. No impairment associated with unproved properties has been recorded for the years ended December 31, 2013 and 2012.

NOTE 6—DERIVATIVES AND FINANCIAL INSTRUMENTS

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

With a costless collar, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the exercise price of the purchased put. The Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the exercise price for the sold call of the collar. The settlement paid or received is the difference between the market price on the settlement date and the related exercise price. All derivative instruments are reflected as either assets or liabilities in the Company's accompanying consolidated balance sheets as of December 31, 2013 and 2012, respectively (see Note 7 for further discussion of fair value). The table below summarizes the fair value (see note 5 for further discussion of fair value) and classification of the Company's derivative instruments:

As of December 31, 2013
(in thousands)

Classification	Balance Sheet Location	Gross Fair Value	Effect of Counter-party Netting	Net Carrying Value on Balance Sheet
Assets:				
Current asset	Commodity derivative asset	$ 2,888	$ (2,850)	$ 38
Non-current asset	Deferred charges and other long-term assets	1,521	(1,504)	17
Total assets		$ 4,409	$ (4,354)	$ 55
Liabilities:				
Current liability	Commodity derivative liability	$ 4,397	$ (2,845)	$ 1,552
Non-current liability	Commodity derivative liability	1,824	(1,509)	315
Total liabilities		$ 6,221	$ (4,354)	$ 1,867

Table of Contents

As of December 31, 2012
(in thousands)

Classification	Balance Sheet Location	Gross Fair Value	Effect of Counter-party Netting	Net Carrying Value on Balance Sheet
Assets:				
Current asset	Commodity derivative asset	$ 8,158	$ (2,946)	$ 5,212
Non-current asset	Deferred charges and other long-term assets	820	(494)	326
Total assets		$ 8,978	$ (3,440)	$ 5,538
Liabilities:				
Current liability	Commodity derivative liability	$ 2,946	$ (2,946)	$ —
Non-current liability	Commodity derivative liability	494	(494)	—
Total liabilities		$ 3,440	$ (3,440)	$ —

Changes in the fair values of the Company's derivative instruments (both assets and liabilities) are presented on a net basis in the accompanying consolidated statements of operations. The following table details the unrealized and realized gains (losses) recognized from the Company's derivative instruments and where these components are recorded on the Company's accompanying consolidated statements of operations for the years ended December 31, 2013 and 2012:

Derivatives not designated as hedging instruments under ASC 815	Location of Gain (Loss)	Classification of Gain(Loss)	Year Ended December 31, 2013	Year Ended December 31, 2012
			(in thousands)	
Oil commodity contracts	Gain (loss) on commodity derivative instruments	Realized	$ (505)	$ (1,040)
Gas commodity contracts	Gain (loss) on commodity derivative instruments	Realized	1,995	24,012
Total realized gains from derivatives not designated as hedges			$ 1,490	$ 22,972
Oil commodity contracts	Gain (loss) on commodity derivative instruments	Unrealized	$ (2,964)	$ 4,076
Gas commodity contracts	Gain (loss) on commodity derivative instruments	Unrealized	(4,386)	(14,773)
Total unrealized losses from derivatives not designated as hedges			$ (7,350)	$ (10,697)

The Company had the following open derivative contracts for oil at December 31, 2013:

Period and Type of Contract	Volume in bbl	Weighted Average	Range Low	Range High
2014				
Collar Contracts:				
Call Options	1,457,000	$102.25	$96.25	$114.15
Put Options	1,457,000	$ 82.49	$75.00	$ 95.00
2015				
Collar Contracts:				
Call Options	249,000	$100.38	$99.05	$101.25
Put Options	249,000	$ 80.08	$80.00	$ 81.00

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The Company had the following open derivative contracts for natural gas at December 31, 2013:

Period and Type of Contract	Volume in MMBtu	Weighted Average	Range Low	Range High
2014				
Collar contracts:				
Call Options	27,360,000	$ 4.83	$4.40	$5.57
Put Options	27,360,000	$ 3.59	$3.30	$4.25
2015				
Collar contracts:				
Call Options	5,860,000	$ 4.95	$4.60	$5.05
Put Options	5,860,000	$ 3.66	$3.50	$3.80

NOTE 7—FAIR VALUE DISCLOSURE

ASC 820, *Fair Value Measurement,* defines fair value as the amount at which an asset (or liability) could be bought (or incurred) or sold (or settled) in a current transaction between willing parties other than in a forced or liquidation sale. 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—Quoted prices (unadjusted) for identical assets or liabilities in active markets.

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

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. There were no transfers into, or out of, the three levels of the fair value hierarchy for the years ended December 31, 2013 and 2012.

The Company estimated the fair value of derivative instruments using the market approach via a model that uses inputs that are observable in the market or can be derived from, or corroborated by, observable data. See Note 6 for further discussion on derivatives and financial instruments.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

	Level 1	Level 2	Level 3 (in thousands)	Effect of Netting	Total
At December 31, 2013					
Financial Assets					
Commodity derivative instruments	$ —	$4,409	$ —	$(4,354)	$ 55
Financial Liabilities					
Commodity derivative instruments	—	6,221	—	(4,354)	$1,867
At December 31, 2012					
Financial Assets					
Commodity derivative instruments	$ —	$8,978	$ —	$(3,440)	$5,538
Financial Liabilities					
Commodity derivative instruments	—	3,440	—	(3,440)	$ —

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

Oil and natural gas properties are measured at fair value on a nonrecurring basis using the income approach as described in Note 2. Proved and unproved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of those properties. Significant Level 3 assumptions used to determine fair value include estimates of proved reserves, future commodity prices, the timing and amount of future production and capital expenditures, and a discount rate commensurate with the risk associated with the respective oil and natural gas properties.

The Company's estimates of fair value have been determined at discrete points in time based on relevant market data. These estimates involve uncertainty and cannot be determined with precision. There were no changes in valuation techniques or related inputs for the years ended December 31, 2013 and 2012.

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

	Fair Value Measurements Using (in millions)				
	Level 1	Level 2	Level 3	Net Book Value	Total Impairment Loss
Year Ended December 31, 2013					
Impaired oil and natural gas properties	$ —	$ —	$56.3	$ 113.4	$ 57.1
Year Ended December 31, 2012					
Impaired oil and natural gas properties	$ —	$ —	$49.3	$ 112.3	$ 63.0

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 8—RELATED PARTY TRANSACTIONS

The Company executed a promissory note dated January 1, 2009 in the aggregate amount of $0.4 million to a member of the Board of Managers (the "Board") of BSNR. The promissory note was secured by security interests in 451,951 common units in BSMC and 456,516 shares in BSNR. The promissory notes provided for (i) accrual of interest at a rate of 2.06% and (ii) a payment schedule of $0.1 million plus accrued interest on each of the following dates: April 15, 2010, April 15, 2011, and April 15, 2012. This promissory note was paid in full in April 2012.

The Company executed promissory notes dated April 15, 2010, in the amount of $0.5 million to officers of the Company. The promissory notes related to the acquisition of a partnership interest in Ivory Acquisitions Partners, L.P. by the officers and the notes were collateralized by a security interest in the Company. The promissory notes provided for quarterly payments of interest at a blended rate of 2.73% and 2.83% at December 31, 2013 and 2012, respectively, equal to the rate at which the Company paid interest on its borrowings. At December 31, 2013 and 2012, less than $0.1 million of interest receivable on the notes was included in prepaid expenses and other current assets on the consolidated balance sheets. At December 31, 2013 and 2012, the aggregated note balances were $0.1 million and $0.2 million, respectively, and were included in prepaid expenses and other current assets, respectively, on the consolidated balance sheets. These promissory notes were paid in full on the maturity date of April 15, 2014. See Note 18 for further discussion on subsequent events.

NOTE 9—SIGNIFICANT CUSTOMERS

The Company leases mineral interests to exploration and production companies and participates in non-operated working interests when economic conditions are favorable. One company represented 10.9% and 12.3% of total revenue for the years ended December 31, 2013 and 2012, respectively.

If the Company were to lose a significant customer, the loss could impact revenue derived from its mineral and royalty interests and working interests. The loss of any single lessee is mitigated by the Company's diversified customer base.

NOTE 10—CREDIT FACILITIES

Senior Line of Credit

In September 2006, the Company entered into a credit agreement ("Senior Line of Credit") with a syndicate of lenders. During the first quarter of 2012, the current Senior Line of Credit was executed to extend the term of the facility to February 3, 2017, at which time all unpaid principal and interest is due. On June 28, 2013, the terms of the Senior Line of Credit were amended to increase the maximum credit amount from the original $600.0 million to $1.0 billion. The borrowing base was $700.0 million and $340.0 million at December 31, 2013 and 2012, respectively. The borrowing base is based on the value of the Company's oil and natural gas properties. Proceeds from the Senior Line of Credit are used for the acquisition of oil and natural gas properties and for other general business purposes.

Borrowings under the Senior Line of Credit bear interest at LIBOR plus a margin between 1.75% and 2.75%, or prime rate plus a margin between 0.75% and 1.75%, with the margin depending on the borrowing base utilization percentage of the loan. The prime rate is determined to be the higher of the financial institution's prime rate or the federal funds effective rate plus one-half of 1% per annum. The weighted average interest rate of the Senior Line of Credit was 2.42% and 3.87% as of December 31, 2013 and 2012, respectively. Accrued interest is payable at the end of each calendar quarter or at the end of each interest period, unless the interest period is longer than 90 days in which case interest is payable at the end of every 90-day period. In addition, a commitment fee is payable at the end of each calendar quarter based on either a rate of 0.375%, if the borrowing base utilization percentage is less than 50%, or 0.50% per annum, if the borrowing base utilization percentage is equal to or greater than 50%. The Senior Line of Credit is secured by substantially all of the Company's oil and natural gas production and assets and is guaranteed by certain operating subsidiaries.

The Senior Line of Credit contains various restrictions on future borrowings, leases and sales of assets. Additionally, the Senior Line of Credit requires the Company to maintain a current ratio of not less than 1.0 and a ratio of total debt to EBITDAX (Earnings before Interest, Taxes, Depreciation, Amortization, and Exploration) of not more than 3.5. At December 31, 2013, the Company was in compliance with all financial covenants in the Senior Line of Credit.

The aggregate principal balance outstanding was $451.0 million and $317.0 million at December 31, 2013 and 2012, respectively. The unused portion of the available borrowings under the Senior Line of Credit was $249.0 million and $23.0 million at December 31, 2013 and 2012, respectively.

Fund II-B Revolving Credit Facility

Black Stone Natural Resources II-B, L.P., a consolidated subsidiary of the Company, obtained a $50.0 million five-year revolving credit facility dated November 9, 2005, as amended, on November 3, 2010, ("Fund II-B Revolving Credit Facility") with a financial institution as the administrative agent and the lender. The Fund II-B Revolving Credit Facility required a 0.5% annual commitment fee that is payable at the end of each calendar quarter. The outstanding balance was $19.1 million at December 31, 2012, with a weighted average interest rate of 3.0%.

The Company repaid the outstanding principal balance on March 28, 2013, and the Fund II-B Revolving Credit Facility was terminated on April 30, 2013.

Fund III-B Revolving Credit Facility

Black Stone Natural Resources III-B, L.P., a consolidated subsidiary of the Company, obtained a $100.0 million revolving credit facility dated October 10, 2008 ("Fund III-B Revolving Credit Facility"), with a financial institution as the administrative agent and the lender. On December 27, 2012, the Fund III-B Revolving Credit Facility was amended and extended through November 30, 2017. The amendment includes a 0.5% annual commitment fee that is payable at the end of each calendar quarter. The outstanding balance was $27.0 million at December 31, 2012 with a weighted-average interest rate of 3.0%.

The Company repaid the outstanding principal balance and terminated the Fund III-B Revolving Credit Facility on May 15, 2013.

NOTE 11—INCENTIVE COMPENSATION

Overview and Valuation Assumptions

The Company has long-term incentive plans for its employees and the Board under which awards can be granted in the form of time-based restricted units and cash awards based on the Company's historical performance. The plans provide that all awards are granted on January 1 of each year. There are no performance criteria or market criteria associated with any of the Company's equity-based awards. The incentive awards vest based on a predetermined schedule as approved by the Board. Compensation expense is included in general and administrative expense on the consolidated statements of operations in the year earned. There is no limit to the number of equity awards that are authorized or issued under the plans. The total compensation expense related to the time-based restricted unit grants is measured as the number of units granted multiplied by the grant-date fair value per unit. Compensation expense is recognized on a straight-line basis over the service period (generally equivalent to the vesting period).

Determining the fair value of the Company is required under the Company's limited partnership agreement for purposes of the Company purchasing common units from those limited partners who exercise their right under the limited partnership agreement to annually sell a portion of their common units. As the Company is privately held, determining the fair value requires the Company to make complex and subjective judgments. To determine the fair value of the Company, the Company engages third-party valuation specialists and relies on generally accepted valuation techniques, which include the net asset value method under the asset approach, the guideline public company method under the market approach, and the dividend discount method of the income approach. These methods are dependent upon various assumptions to develop the estimates in the Company's operating results, commodity prices, and market-based discount rates. The Company also considers publicly available information on comparable public companies and the Company's historical transactions and performance in making these estimates. There is inherent uncertainty in making these estimates. The Company utilizes the same valuation for issuances of equity, if any, and as the basis for calculating fair value of its equity awards under its long-term incentive plans.

Prior to December 31, 2013, one unit of the equity-based awards under all effective incentive plans consisted of 1 share of BSNR and 0.99 Class A common units of BSMC. On December 31, 2013, the Company simplified its corporate structure, and BSNR became a 100% owned subsidiary of BSMC. Accordingly, the underlying interest in one unit of the equity-based awards of the Company did not change as a result of the transaction. See Note 1 for further discussion of the business and basis of presentation.

Employee Long-Term Incentive Plans

Effective January 1, 2006, the Company adopted an Employee Long-Term Incentive Plan, as amended, ("ELTI Plan"), in which employees other than management and senior management are entitled to earn cash bonuses based on the growth in the fair value of the Company in the preceding year (the "Incentive Year). The fair value of the Company is determined based on a third-party valuation. The ELTI Plan has a service period of five years. Payments under the ELTI Plan are disbursed 25% per year over a four-year period on December 31 of each year following the incentive year.

Effective January 1, 2012, the Company adopted an amended version of its long-term incentive plan for employees ("New ELTI Plan"). Under the New ELTI Plan, employees are entitled to earn cash bonuses over a four-year service period. Payments under the New ELTI Plan are disbursed one-third per year over three years beginning on the first anniversary of the award date.

Management and Senior Management Long-Term Incentive Plans

Effective January 1, 2009, the Company adopted a Management Employee Long-Term Incentive Plan, as amended, ("MLTI Plan"), in which members of management other than senior management are eligible to earn cash bonuses based on the growth in the fair value of the Company in the Incentive Year. The fair value of the Company is determined based on a third-party valuation. The participants may choose to receive up to 20% of their cash bonus in restricted common units in the Company at the end of the Incentive Year, under the condition that the Company has the right to repurchase these restricted common units. Election has to be made within 120 days after the last day of an Incentive Year. The number of restricted common units is determined based on the value of the cash bonus elected to be converted to the equity-based awards and the fair value of a common unit of the Company on the date of grant. The equity bonuses under the MLTI Plan vest on a graded schedule over a five year service period. Payments under the MLTI Plan are disbursed equally over a four-year period, with one-fourth payable every December 31 beginning on the first anniversary of the last day of an Incentive Year.

Effective January 1, 2009, the Company adopted a Senior Management Long-Term Incentive Plan, as amended, (“SMLTI Plan”), under which senior management is eligible to earn cash and equity bonuses based on the growth in fair value of the Company during the Incentive Year, the annual total returns during the three-year period preceding the award date, and a Board determined discretionary amount believed to approximate compensation offered to senior executives of comparable companies. Fifty percent of the bonus is immediately expensed upon a lump-sum cash payment, and the remaining fifty percent is made in restricted common units of the Company, that vest ratably over three years. Payments under the SMLTI Plan are disbursed on March 15 immediately following the Incentive Year for the portion of the award.

Effective January 1, 2012, the Company adopted a new long-term incentive plan that combines both its management and senior management long-term incentive plans (“New MLTI Plan”). Under the New MLTI Plan, half of the incentive compensation is payable in cash and determined based on achieving specific production and reserves targets as set by the Board. The remainder is determined based on continued employment with the Company. Cash award compensation under the New MLTI Plan cliff vests on the third anniversary of the award date, subject to satisfaction of the performance targets. For the awards granted in 2012, the Company made a modification to the vesting terms of the New MLTI Plan to conform the cash vesting schedule to the equity vesting schedule described below.

Equity compensation under the New MLTI Plan is paid in the form of restricted common units of BSMC. The restricted common units awarded are subject to restrictions on transferability, customary forfeiture provisions and time vesting provisions. One-third of each award vests on the first, second, and third anniversaries of the date of grant. Award recipients have all the rights of a unitholder in BSMC with respect to the restricted common units vested, including the right to receive distributions thereon, if and when distributions are made by the BSMC to its limited partners. Award recipients may request that the Company, at its discretion, repurchase up to 50% of the restricted common units that are vested. As a result of the repurchase option, 50% of the equity awards to be vested on each vesting date are classified as a liability during the corresponding year prior to the vesting date until a request for the Company to repurchase is made by the recipient, or the repurchase option period ends, which is 30 days prior to the vesting date. The liability is measured periodically at fair value. At year-end, the balance of the liability equals the fair value of the equity awards that have been elected and approved for repurchase on the vesting date. At December 31, 2013, and 2012, the liability balances related to these equity-based awards were zero, and all vested awards were classified as equity. During the years ended December 31, 2013 and 2012, no election was made to settle the equity-based awards in cash, and the Company made no payment on the equity-based liabilities.

The aggregate fair value of the restricted common units awarded to the Company’s management and senior management during the years ended December 31, 2013 and 2012, was $7.4 million and $7.4 million, respectively.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Management and Senior Management Long Term Incentive Plans	Common Units (in millions)	Weighted-Average Grant Date Fair Value per Share(1)
Unvested at December 31, 2011	2.1	$ 1.84
Granted(2)	4.6	$ 1.61
Vested	(3.1)	$ 1.74
Unvested at December 31, 2012	3.6	$ 1.65
Granted(3)	4.6	$ 1.60
Vested	(3.1)	$ 1.62
Forfeited	(0.6)	$ 1.61
Unvested at December 31, 2013	4.5	$ 1.71

(1) Determined by dividing the aggregate grant-date fair value of awards by the number of awards issued.
(2) The aggregate grant-date fair value of restricted common unit awards issued in 2012 was $7.4 million based on third-party valuation reports.
(3) The aggregate grant-date fair value of restricted common unit awards issued in 2013 was $7.4 million based on third-party valuation reports.

The unrecognized compensation cost associated with restricted common unit awards was $7.2 million and $6.0 million at December 31, 2013 and 2012, respectively, which the Company expects to recognize over a weighted-average period of 2.0 years and 1.7 years, respectively. During the year ended December 31, 2013, an executive of the Company resigned, resulting in the forfeiture of 0.6 million restricted common units. This resulted in the reversal of $0.5 million in equity-based compensation recognized in 2013 and reduced unearned compensation expense by $0.5 million as of December 31, 2013.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Board of Managers Long-Term Incentive Plan

Effective January 1, 2009, the Company adopted a Board of Managers Incentive Plan, as amended, ("BMI Plan"), under which the Board is entitled to cash and restricted common unit bonuses for each year of service. The restricted common units awarded are subject to restrictions on transferability.

The aggregate fair value of the restricted common units awarded to the Board during the years ended December 31, 2013 and 2012 was $2.1 million and $1.9 million, respectively. The restricted common units granted are accounted for as equity-based awards. The grant-date fair value is recognized as compensation cost on a straight-line basis over the service period (generally equivalent to the vesting period).

Board of Managers Long-Term Incentive Plans	Common Units (in millions)	Weighted-Average Grant Date Fair Value per unit(1)
Unvested at December 31, 2011	1.2	$ 1.72
Granted(2)	1.2	$ 1.61
Vested	(1.2)	$ 1.71
Unvested at December 31, 2012	1.2	$ 1.70
Granted(3)	1.3	$ 1.60
Vested	(1.2)	$ 1.62
Unvested at December 31, 2013	1.3	$ 1.60

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.
(2) The aggregate grant date fair value of restricted common unit awards issued in 2012 was $1.9 million based on grant date market prices.
(3) The aggregate grant date fair value of restricted common unit awards issued in 2013 was $2.1 million based on grant date market prices.

There were no forfeitures during the years ended December 31, 2013 and 2012 in relation to the BMI Plan. The unrecognized compensation cost associated with restricted common unit awards was an aggregate $2.1 million and $2.0 million at December 31, 2013 and 2012, respectively, which the Company expects to recognize over a weighted-average period of 1.7 years.

The table below summarizes incentive compensation expenses recorded in general and administrative expenses in the consolidated statements of operations for the years ended December 31, 2013 and 2012, respectively.

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Employee Long-term Incentive Plans, net of estimated forfeiture of $0.3 and $0.2, respectively	$ 5,924	$ 4,565
Cash—Management and Senior Management Long-term Incentive Plan, net of forfeiture of $1.0 and $0, respectively	4,281	5,307
Equity-based Compensation—Management and Senior Management Long-term Incentive Plan, net of estimated forfeiture of $0.3 and $0, respectively	4,754	5,251
Board of Managers Long-term Incentive Plans, net of estimated forfeiture of $0 and $0, respectively	2,028	1,997
Total compensation expense	$16,987	$17,120

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 12—EMPLOYEE BENEFIT PLANS

The Company sponsors a 401(k) Profit Sharing Plan (the "Plan"), a defined contribution plan, for the benefit of substantially all employees of the Company. The Plan became effective on January 1, 2001 and allows eligible employees to make tax-deferred contributions up to 100% of their annual compensation, not to exceed annual limits established by the Internal Revenue Service. The Company makes matching contributions of 100% of employee contributions, up to 5% of compensation. These matching contributions are subject to a graded vesting schedule, with 33% vested after one year, 66% vested after two years and 100% vested after the initial three years of employment with the Company. Following three years of employment, future Company matching contributions vest immediately. The Company's contributions were $0.5 million for both the years ended December 31, 2013 and 2012.

NOTE 13—COMMITMENTS AND CONTINGENCIES

Leases

The Company leases certain office space and equipment under cancelable and non-cancelable operating leases. The Company recognizes rent expense on a straight-line basis over the lease term. Rent expense under such arrangements was $1.9 million and $1.6 million for the years ended December 31, 2013 and 2012, respectively. Such amounts are included in general and administrative expense on the consolidated statements of operations.

Future minimum lease commitments, in thousands, under non-cancelable leases are as follows:

Year Ending December 31,	(in thousands)
2014	$ 1,294
2015	1,337
2016	1,319
2017	11
	$ 3,961

Environmental Matters

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

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

Litigation

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

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 14—REDEEMABLE PREFERRED UNITS

As of December 31, 2013 and 2012, the Company has outstanding 157,424 Series A preferred units (the "Preferred Units") for $161.4 million (which includes accrued and unpaid dividends of $4.0 million as of both December 31, 2013 and 2012). The Preferred Units are classified as mezzanine equity on the consolidated balance sheets since redemption is outside the control of the Company. The owners of Preferred Units are entitled to an annual dividend coupon of 10% for the funded capital of the Preferred Units payable on a quarterly basis in arrears. For each of the years ended December 31, 2013 and 2012, the Company paid dividends on preferred units of $15.7 million and $15.8 million, respectively.

The Preferred Units are convertible into common units at any time at the option of the preferred unitholders. The Preferred Units have an initial conversion price of $1.1020948 and an initial conversion rate of 907.36296 common units per Preferred Unit. In the event the preferred unitholders have not converted all of the Preferred Units by December 31, 2014, the owners of the Preferred Units can elect to have the Company redeem up to 25% per year of its Preferred Units at face value, plus any accrued and unpaid dividends, on December 31 of each year from 2014 to 2017. The Company shall have the right, at its sole option, to redeem an amount of Preferred Units equal to the units being redeemed by an owner of Preferred Units on each December 31. Any amount of a given year's 25% of Preferred Units not redeemed on December 31 shall automatically convert to common units on January 1 of the following year. No Preferred Units were converted into common units during the years ended December 31, 2013 and 2012.

NOTE 15—EXCHANGE OFFER AND EQUITY OFFERING

During 2012, the Company presented a proposal to purchase the noncontrolling interests in certain subsidiaries in exchange for cash or common units of BSMC (the "Exchange Offer"). The Exchange Offer resulted in a majority of the noncontrolling investors electing to exchange their interests in the subsidiaries for cash or common units of BSMC, substantially all of which were Class B common units. The interests purchased totaled approximately $222.9 million in December 31, 2012. The consolidated balance sheets include $23.3 million of accrued noncontrolling interest repurchases as of December 31, 2012. The Company used borrowings under the Senior Line of Credit and proceeds from a concurrent $412.2 million common unit offering ("Equity Offering"), effective January 1, 2013, to fund the cash used to purchase the noncontrolling interests. Cash from the Equity Offering above the amounts needed for the Exchange Offer was used to repay a portion of the Senior Line of Credit and provide additional resources for future acquisitions. The Exchange Offer also consisted of the issuance of $1,017 million of Class B common units and $2 million of Class A common units.

Significant terms for the Class B common units include Board and committee representation, conversion rights to Class A common units upon the occurrence of certain events and registration rights. Other than Board and committee representation, the Class A common units and Class B common units contain the same rights and preferences. As a result, they are collectively referred to as the "common units". Proceeds from the Equity Offering that were received prior to January 1, 2013, are classified as deferred partner contributions in the consolidated balance sheet at December 31, 2012.

NOTE 16—NONCONTROLLING INTERESTS

The Company has ownership interests in multiple partnerships that are consolidated in the Company's financial statements. At the end of 2012 and the beginning of 2013, the Company purchased a majority of the interests held by the third-party partners with cash or equity of BSMC through the Exchange Offer and Equity Offering discussed in Note 15. Cash purchases of noncontrolling interests were effective on December 31, 2012, and equity exchanges or new issuances were effective as of January 1, 2013.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

On January 1, 2013, the Company dissolved Black Stone Natural Resources I, LP ("BSNR I") and Black Stone Natural Resources Raptor, L.P. ("BSNR Raptor") and distributed the underlying assets to unrelated third-party investors on a pro rata basis, which resulted in a distribution of property. In August 2013, BSMC purchased the remaining third-party investors' interests in Black Stone Natural Resources II, L.P. ("BSNR II") for $37.4 million. As a result of the transactions, the only remaining noncontrolling interest at December 31, 2013 was the 10.6% interest in O'Connell Partners, L.P., as discussed in Note 15.

As a result of the aforementioned transaction and the Exchange Offer described in Note 15 above, BSMC owns all of the limited partnership interests in its consolidated subsidiaries as of December 31, 2013, except for an 89.4% interest in O'Connell Partners, L.P., one of the subsidiaries consolidated by the Company.

The following table summarizes the effects of changes in the noncontrolling interest on the Company's equity for the years ended December 31, 2013 and 2012:

	Year Ended December 31,	
	2013	2012
	(in thousands)	
Net income attributable to common units	$152,848	$ 91,725
Transfers from noncontrolling interests:		
Increase in the Company's ownership due to Exchange Offer (Note 15)	289,604	(118,587)
Increase in the Company's ownership due to purchase of BSNR II noncontrolling interests	(22,696)	—
Net transfers (to) from noncontrolling interests	266,908	(118,587)
Change from net income attributable to unitholders and transfers from noncontrolling interests	$419,756	$ (26,862)

NOTE 17—EARNINGS PER UNIT

Class A common units and Class B common units have been combined as a single class for purposes of basic and diluted earnings per unit ("EPU") as they contain the same economic rights and preferences. The holders of the Company's restricted common units have all the rights of a unitholder, including non-forfeitable distribution rights. As participating securities, the restricted common units are included in the calculation of basic earnings per unit using the two-class method. For the periods presented, the amount of earnings allocated to the participating restricted common units was not material. The redeemable Preferred Units can be converted into 142.8 million common units as of both December 31, 2013 and 2012. At December 31, 2013 and 2012, if the redeemable Preferred Units were converted to common units, their effect would be anti-dilutive; therefore, the redeemable Preferred Units are not included in the diluted EPU calculation.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table sets forth the computation of basic and diluted earnings per unit (in thousands, except per unit amounts):

	Year Ended December 31, 2013	Year Ended December 31, 2012
	(in thousands)	
Net income	$ 168,963	$ 151,810
Less: Net income attributable to noncontrolling interests	(373)	(44,343)
Net income attributable to Black Stone Minerals Company, L.P.	168,590	107,467
Less: Dividends on preferred units	(15,742)	(15,742)
Net income available to common units	$ 152,848	$ 91,725
Weighted average units outstanding (basic and diluted)	2,144,599	1,212,885
Basic and diluted earnings per unit	$ 0.07	$ 0.08

NOTE 18—SUBSEQUENT EVENTS

On January 15, 2014, the Company paid distributions of approximately $0.6 million and $54.5 million to BSNR and the holders of BSMC common units, respectively, and approximately $4.0 million to the owners of the Preferred Units. These payments were netted with receivables from the partners of the Company and accrued in accrued partners' distribution payable—related party on the consolidated balance sheet as of December 31, 2013. See Note 8 for further discussion of related party transactions.

On January 24, 2014, the Company purchased an undivided mineral interest in approximately 6,300 acres in McMullen County, Texas. The adjusted purchase price was approximately $11.9 million.

On March 12, 2014, the Company acquired producing properties and leasehold interests in San Augustine County, Texas, from Encana Corporation for $24.6 million. Additionally, as part of the transaction, the Company assumed Encana's position in the Comanche prospect in Shackelford and Throckmorton Counties, Texas.

On April 14, 2014, the Company paid distributions of approximately $56.3 million to the holders of BSMC's common units and approximately $3.9 million to the owners of the Preferred Units.

On July 15, 2014, the Company paid distributions of approximately $56.3 million to the holders of BSMC's common units and approximately $3.9 million to the owners of the Preferred Units.

On July 17, 2014, the Company acquired producing properties and leasehold interests in Reagan and Upton Counties, Texas, for $12.5 million.

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Supplemental Oil and Gas Disclosures—UNAUDITED

Geographic Area of Operation

All of our proved reserves are located within the continental United States, with the majority concentrated in Kentucky, Louisiana, North Dakota, Oklahoma, Pennsylvania, Texas, West Virginia and Wyoming; however, the Company also owns mineral and royalty interests and non-operated working interests in various producing and non-producing oil and natural gas properties in several other areas throughout the United States. Therefore, the following disclosures about our costs incurred and proved reserves are on a total company basis.

Costs Incurred in Oil and Natural Gas Property Acquisitions, Exploration, and Development Activities

Costs incurred in oil and natural gas property acquisition, exploration and development, whether capitalized or expensed, are presented below:

	Year ended December 31,	
	2013	2012
Acquisition Costs of Properties:(1)		
Proved	$ 77,580	$ 23,501
Unproved	264,710	84,204
Exploration Costs	357	455
Development Costs	50,440	80,134
Total	$ 393,087	$ 188,294

(1) See Note 4 for details about the Company's significant acquisitions.

Oil and Natural Gas Capitalized Costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, and amortization are presented below:

	Year ended December 31,	
	2013	2012
Proved properties	$1,637,223	$1,515,848
Unproved properties	640,291	369,071
Total	2,277,514	1,884,919
Accumulated depreciation, depletion and amortization	(965,371)	(817,950)
Net capitalized costs	$1,312,143	$1,066,969

Oil and Gas Natural Reserve Information

The following sets forth estimated quantities of our net proved, proved developed and proved undeveloped oil and natural gas reserves. These reserve estimates exclude insignificant natural gas liquid quantities owned by the Company. Estimated reserves for the periods presented are based on the unweighted average of first-day-of-the-month commodity prices over the period January through December for the year in accordance with definitions and guidelines set forth by the SEC and the FASB.

	Crude Oil (Mbbl)	Natural Gas (Mmcf)	Total(8) (MBoe)
Net proved reserves at December 31, 2011	12,992	285,964	60,653
Revisions of previous estimates(1)	1,698	(14,000)	(635)
Purchases of minerals in place(2)	122	4,451	864
Extensions, discoveries and other additions(3)	2,172	50,350	10,563
Production	(2,173)	(52,965)	(11,001)
Net proved reserves at December 31, 2012	14,811	273,800	60,444
Revisions of previous estimates(1)	1,616	(16,762)	(1,177)
Purchases of minerals in place(4)	883	5,472	1,795
Extensions, discoveries and other additions(5)	4,265	22,850	8,073
Production	(2,626)	(45,400)	(10,193)
Net proved reserves at December 31, 2013	18,949	239,960	58,942
Net Proved Developed Reserves(6)			
December 31, 2012	14,395	242,814	54,864
December 31, 2013	17,290	232,777	56,086
Net Proved Undeveloped Reserves(7)			
December 31, 2012	416	30,986	5,580
December 31, 2013	1,659	7,183	2,856

(1) Revisions of previous estimates include technical revisions due to changes in commodity prices, historical and projected performance and other factors. The most notable technical revisions are related to well performance in certain Haynesville shale wells.

(2) Includes the acquisition of Pure mineral interests as part of the Exchange Offer and other mineral acreage located in Louisiana and Texas. See Note 4—Acquisitions and Note 15—Exchange Offer and Equity Offering for additional details.

(3) Include discoveries and additions primarily related to active drilling in the Haynesville, Bakken, Wilcox, Granite Wash, and Lance-Mesavede plays.

(4) Includes the acquisition of Pure mineral interests as part of the Exchange Offer and other mineral acreage located in the Eagle Ford Shale in Texas. Additionally, this line includes adjustments to reserves related to the distribution of the assets in Fund I and BSNR Raptor to unrelated third-party investors. See Note 4—Acquisitions, Note 15—Exchange Offer and Equity Offering and Note 16—Noncontrolling Interest for additional details.

(5) Includes discoveries and additions primarily related to active drilling in the Haynesville, Bakken, Wilcox, Granite Wash, and Fayetteville shale plays.

(6) Proved developed reserves of 119 MBOE and 19,534 MBOE as of December 31, 2013 and 2012, respectively, were attributable to noncontrolling interests in our consolidated subsidiaries.

(7) As of December 31, 2013, no proved undeveloped reserves were attributable to noncontrolling interests. Proved undeveloped reserves 2,398 MBOE as of December 31, 2012 were attributable to noncontrolling interests in our consolidated subsidiaries.

Table of Contents

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(8) The conversion to barrels of oil equivalent and cubic feet equivalent were determined using the energy-equivalent ratio of six Mcf of natural gas to one Bbl of crude oil (totals may not compute due to rounding). The energy-equivalent ratio does not assume price equivalency, and the energy-equivalent prices for oil and natural gas may differ significantly.

Standardized Measure of Discounted Future Net Cash Flows

Future cash inflows represent expected revenues from production of period-end quantities of proved reserves based on the unweighted average of first-day-of-the-month commodity prices for the periods presented. All prices are adjusted by field for quality, transportation fees, energy content and regional price differentials. Future cash inflows are computed by applying applicable prices relating to the Company's proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. There are no future income tax expenses because the Company is not subject to federal income taxes. The Company is subject to certain state based taxes; however, these amounts are not material. See Note 2 for additional information about income taxes.

	Year ended December 31, 2013	2012
	(In thousands)	
Future cash inflows	$ 2,693,511	$2,138,461
Future production costs	(393,347)	(329,646)
Future development costs	(53,160)	(55,089)
Future net cash flows (undiscounted)	2,247,004	1,753,726
Annual discount 10% for estimated timing	(1,061,747)	(825,209)
Total(1)	$ 1,185,257	$ 928,517

(1) Includes standardized measure of discounted future net cash flows of approximately $1.4 million and $271.1 million as of December 31, 2013 and 2012, respectively, are attributable to noncontrolling interests in our consolidated subsidiaries.

The following summarizes the principal sources of change in the standardized measure of discounted future net cash flows:

	For the years ended December 31, 2013	2012
	(In thousands)	
Standardized measure, beginning of year	$ 928,518	$1,071,848
Sales, net of production costs	(373,655)	(312,201)
Net changes in prices and production costs related to future production	208,291	(82,200)
Extensions, discoveries and improved recovery, net of future production and development costs	223,482	138,841
Development costs incurred during the period	22,456	17,702
Revisions of estimated future development costs	1,620	(3,399)
Revisions of previous quantity estimates, net of related costs	(22,687)	(10,881)
Accretion of discount	92,852	107,185
Purchases of reserves in place, less related costs	62,887	12,418
Other	41,493	(10,795)
Standardized measure, end of year	$1,185,257	$ 928,518

BLACK STONE MINERALS COMPANY, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

Appendix A

FORM OF FIRST AMENDED AND RESTATED AGREEMENT OF LIMITED PARTNERSHIP
OF
BLACK STONE MINERALS, L.P.

Appendix B

GLOSSARY OF TERMS

The following are definitions of certain terms used in this prospectus.

Basin. A large depression on the earth's surface in which sediments accumulate.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume.

Bbl/d. Bbl per day.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of oil, condensate, or natural gas liquids.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

Boe/d. Boe per day.

British Thermal Unit (Btu). The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilling well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Crude oil. Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.

Delaware Act. Delaware Revised Uniform Limited Partnership Act.

Delay rental. Payment made to the lessor under a non-producing oil and natural gas lease at the end of each year to defer a drilling obligation and continue the lease for another year during its primary term.

Deterministic method. The method of estimating reserves or resources under which a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development costs. Capital costs incurred in the acquisition, exploitation, and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Development well. A well drilled within the proved area of an oil and natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry gas. A natural gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.

Dry hole or dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Economically producible. A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Electrical log. Provide information on porosity, hydraulic conductivity, and fluid content of formations drilled in fluid-filled boreholes.

Exploration. A drilling or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

Extension well. A well drilled to extend the limits of a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

Fracturing. The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

Hydraulic fracturing. A process used to stimulate production of hydrocarbons. The process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production.

Lease bonus. Usually a one-time payment made to a mineral owner as consideration for the execution of an oil and natural gas lease.

Lease operating expense. All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constituting part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, allocated overhead charges, workover, insurance, and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil.

MBoe/d. MBoe per day.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

Mineral interests. Real-property interests that grant ownership of the oil and natural gas under a tract of land and the rights to explore for, drill for, and produce oil and natural gas on that land or to lease those exploration and development rights to a third party.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

Net acres or net wells. The sum of the fractional working interest owned in gross acres.

Net revenue interest. An owner's interest in the revenues of a well after deducting proceeds allocated to royalty, overriding royalty, and other non-cost bearing interests.

Natural gas. A combination of light hydrocarbons that, in average pressure and temperature conditions, is found in a gaseous state. In nature, it is found in underground accumulations, and may potentially be dissolved in oil or may also be found in its gaseous state.

Nonparticipating royalty interest (NPRI). A type of non-cost-bearing royalty interest, which is carved out of the mineral interest and represents the right, which is typically perpetual, to receive a fixed cost-free percentage of production or revenue from production, without an associated right to lease.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil and condensate.

Oil and natural gas properties. Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.

Operator. The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Overriding royalty interest (ORRI). A fractional, undivided interest or right of participation in the oil or gas, or in the proceeds from the sale of the oil or gas, produced from a specified tract or tracts, which are limited in duration to the terms of an existing lease and which are not subject to any portion of the expense of development, operation or maintenance.

PDP. Proved developed producing.

Play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Pooling. The majority of our producing acreage is pooled with third-party acreage. Pooling refers to an operator's consolidation of multiple adjacent leased tracts, which may be covered by multiple leases with multiple lessors, in order to maximize drilling efficiency or to comply with state mandated well spacing requirements. Pooling dilutes our royalty in a given well or unit, but it also increases both the acreage footprint and the number of wells in which we have an economic interest. To estimate our total potential drilling locations in a given play, we include third-party acreage that is pooled with our acreage.

Production Costs. The production or operational costs incurred while extracting and producing, storing, and transporting oil and/or natural gas. Typical of these costs are wages for workers, facilities lease costs, equipment maintenance, logistical support, applicable taxes, and insurance.

PUD. Proved undeveloped.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved developed producing reserves. Reserves expected to be recovered from existing completion intervals in existing wells.

Proved reserves. The estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

Pugh clauses. Provides that a well on a pooled area only maintains that portion of the lease within the pooled area. When an operator is producing from pooled acreage that only includes part of a lease tract, Pugh clauses prevent operators from holding the entire leased tract with the production from the pooled unit. As to the other areas of the lease outside the pooled area, the lessor will have to pay rentals, drill wells, or obtain production as necessary to maintain that outside acreage, or else it terminates. Pugh clauses can also be used to limit the area within a lease that can be maintained by a well on the lease or to provide that a well can only maintain lease rights down to a certain depth, resulting in the release of unexplored deep rights, the latter provision sometimes called a horizontal Pugh clause.

Reliable technology. A grouping of one or more technologies (including computation methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Reserves. Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Resource play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism, and hydrocarbon type.

Royalty interest. An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.

Seismic data. Seismic data is used by scientists to interpret the composition, fluid content, extent, and geometry of rocks in the subsurface. Seismic data is acquired by transmitting a signal from an energy source, such as dynamite or water, into the earth. The energy so transmitted is subsequently reflected beneath the earth's surface and a receiver is used to collect and record these reflections.

Shale. A fine grained sedimentary rock formed by consolidation of clay- and silt-sized particles into thin, relatively impermeable layers. Shale can include relatively large amounts of organic material compared with other rock types and thus has the potential to become rich hydrocarbon source rock. Its fine grain size and lack of permeability can allow shale to form a good cap rock for hydrocarbon traps.

Shut-in royalty. Payment to royalty owners under the terms of a mineral lease that allows the operator or lessee to defer production from a shut-in well.

Spacing. The distance between wells producing from the same reservoir and is often established by regulatory agencies.

Standardized measure. The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Because we are a limited partnership, we are generally not subject to federal or state income taxes and thus make no provision for federal or state income taxes in the calculation of our standardized measure. Standardized measure does not give effect to derivative transactions.

Tight formation. A formation with low permeability that produces natural gas with low flow rates for long periods of time.

Trend. A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical, or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest. An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate crude oil, which is a light, sweet crude oil, characterized by an American Petroleum Institute gravity, of API gravity, between 39 and 41 and a sulfur content of approximately 0.4 weight percent that is used as a benchmark for the other crude oils.

Table of Contents

Black Stone Minerals, L.P.

Common Units
Representing Limited Partner Interests

Prospectus
, 2014

Barclays

Through and including , 2014 (25 days after the date of this prospectus), all dealers that buy, sell or trade our common units, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

PART II
INFORMATION NOT REQUIRED IN THE PROSPECTUS

ITEM 13. OTHER EXPENSES OF ISSUANCE AND DISTRIBUTION.

Set forth below are the expenses (other than the underwriting discount) expected to be incurred in connection with the issuance and distribution of the securities registered hereby. With the exception of the SEC registration fee, the NYSE listing fee and the FINRA filing fee, the amounts set forth below are estimates.

SEC registration fee	$ *
NYSE listing fee	*
FINRA filing fee	*
Printing expenses	*
Fees and expenses of legal counsel	*
Accounting fees and expenses	*
Transfer agent and registrar fees	*
Miscellaneous	*
Total	*

* To be provided by amendment.

ITEM 14. INDEMNIFICATION OF OFFICERS AND THE DIRECTORS OF THE BOARD OF DIRECTORS OF OUR GENERAL PARTNER.

The section of the prospectus entitled “The Partnership Agreement—Indemnification” is incorporated herein by reference and discloses that we will generally indemnify the directors, officers, and affiliates of the general partner against all losses, claims, damages or similar events. Subject to any terms, conditions or restrictions set forth in the partnership agreement, Section 17-108 of the Delaware Revised Uniform Limited Partnership Act empowers a Delaware limited partnership to indemnify and hold harmless any partner or other person from and against all claims and demands whatsoever.

Section 18-108 of the Delaware Limited Liability Company Act provides that a Delaware limited liability company may indemnify and hold harmless any member or manager or other person from and against any and all claims and demands whatsoever. The amended and restated limited liability company agreement of BSNR, our general partner, provides for the indemnification of its directors and executive officers against liabilities they incur in their capacities as such.

The underwriting agreement that we expect to enter into with the underwriters, the form of which will be filed as Exhibit 1.1 to this registration statement, will contain indemnification and contribution provisions that will indemnify and hold harmless the directors and executive officers of our general partner.

ITEM 15. RECENT SALES OF UNREGISTERED SECURITIES.

In connection with our formation in September 2014, we issued (i) the non-economic general partner interest to BSNR, our general partner, and (ii) the 99.0% limited partner interest in us to Black Stone Minerals Company, L.P. for $100.00, which interest will be redeemed and cancelled in connection with the closing of the initial public offering of common units of the Partnership and the merger of BSMC with and into Merger Sub, with BSMC as the surviving entity. These issuances were exempt from registration under Section 4(2) of the Securities Act. There have been no other sales of unregistered securities within the past three years. In connection with the merger, the limited partner interests of BSMC will be exchanged for common units and preferred units of the Partnership.

ITEM 16. EXHIBITS.

See the Exhibit Index on the page immediately preceding the exhibits for a list of exhibits filed as part of this registration statement on Form S-1, which Exhibit Index is incorporated herein by reference.

ITEM 17. UNDERTAKINGS.

The undersigned Registrant hereby undertakes to provide to the underwriters at the closing specified in the underwriting agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted to directors, officers and controlling persons of the Registrant pursuant to the provisions described in Item 14 above, or otherwise, the Registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the Registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes that:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this Registration Statement in reliance upon Rule 430A and contained in a form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this Registration Statement as of the time it was declared effective; and

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at the time shall be deemed to be the initial bona fide offering thereof.

The Registrant undertakes to send to each common unitholder, at least on an annual basis, a detailed statement of any transactions with Registrant, our general partner or any of its affiliates, and of fees, commissions, compensation and other benefits paid, or accrued to, Registrant or its affiliates for the fiscal year completed, showing the amount paid or accrued to each recipient and the services performed.

The Registrant undertakes to provide to the common unitholders the financial statements required by Form 10-K for the first full fiscal year of operations of the Registrant.

[Table of Contents](#)

SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant has duly caused this Registration Statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on , 2014.

Black Stone Minerals, L.P.
By: Black Stone Natural Resources, L.L.C., its general partner

By: ______________________________
Name: Thomas L. Carter, Jr.
Title: President, Chief Executive Officer, and Chairman

Each person whose signature appears below appoints Thomas L. Carter, Jr., Marc Carroll and Steve Putman, and each of them, any of whom may act without the joinder of the other, as his or her true and lawful attorneys-in-fact and agents, with full power of substitution and re-substitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Registration Statement and any Registration Statement (including any amendment thereto) for this offering that is to be effective upon filing pursuant to Rule 462(b) under the Securities Act of 1933, as amended, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done, as fully to all intents and purposes as he might or would do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them of their or his or her substitute and substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, as amended, this Registration Statement has been signed below by the following persons in the capacities and the dates indicated.

Signature	Title	Date
Thomas L. Carter, Jr.	President, Chief Executive Officer, and Chairman (Principal Executive Officer)	, 2014
Marc Carroll	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	, 2014
	Director	, 2014
	Director	, 2014
	Director	, 2014

EXHIBIT INDEX

Exhibit Number			Description
1.1	**	—	Form of Underwriting Agreement
3.1	*	—	Certificate of Limited Partnership of Black Stone Minerals, L.P.
3.2	**	—	Form of First Amended and Restated Limited Partnership Agreement of Black Stone Minerals, L.P. (included as Appendix A in the prospectus included in this Registration Statement)
4.1	**	—	Form of Registration Rights Agreement
5.1	**	—	Opinion of Vinson & Elkins L.L.P. as to the legality of the securities being registered
8.1	**	—	Opinion of Vinson & Elkins L.L.P. relating to tax matters
10.1	**	—	Form of Black Stone Minerals, L.P. Long-Term Incentive Plan
10.2	**	—	Form of Credit Agreement
21.1	**	—	List of Subsidiaries of Black Stone Minerals, L.P.
23.1	**	—	Consent of UHY LLP
23.2	**	—	Consent of Pressler Petroleum Consultants, Inc.
23.4	**	—	Consent of Vinson & Elkins L.L.P. (contained in Exhibit 5.1)
23.5	**	—	Consent of Vinson & Elkins L.L.P. (contained in Exhibit 8.1)
24.1	**	—	Powers of Attorney (included on page II-3)
99.1	*	—	Report of Pressler Petroleum Consultants, Inc.

* Provided herewith.
** To be filed by amendment.

Exhibit 3.1

Delaware

The First State

I, JEFFREY W. BULLOCK, SECRETARY OF STATE OF THE STATE OF DELAWARE, DO HEREBY CERTIFY THE ATTACHED IS A TRUE AND CORRECT COPY OF THE CERTIFICATE OF LIMITED PARTNERSHIP OF "BLACK STONE MINERALS, L.P.", FILED IN THIS OFFICE ON THE SIXTEENTH DAY OF SEPTEMBER, A.D. 2014, AT 12:16 O'CLOCK P.M.

Jeffrey W. Bullock, Secretary of State

5603974 8100

AUTHENTICATION: 1701037

141183001

DATE: 09-16-14

You may verify this certificate online at corp.delaware.gov/authver.shtml

Execution Version

CERTIFICATE OF LIMITED PARTNERSHIP
OF
BLACK STONE MINERALS, L.P.

This Certificate of Limited Partnership of Black Stone Minerals, L.P. (the "***Partnership***"), dated September 16, 2014, has been duly executed, and is filed pursuant to Sections 17-201 and 17- 204 of the Delaware Revised Uniform Limited Partnership Act (the "***Act***") to form a limited partnership under the Act.

1. ***Name.*** The name of the Partnership is Black Stone Minerals, L.P.

2. ***Registered Office; Registered Agent.*** The address of the registered office required to be maintained by Section 17-104 of the Act is:

c/o The Corporation Trust Company
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware 19801
New Castle County

The name and address of the registered agent for service of process required to be maintained by Section 17-104 of the Act are:

The Corporation Trust Company
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware 19801
New Castle County

3. ***General Partner.*** The name and the business, residence, or mailing address of the general partner are:

Black Stone Natural Resources, L.L.C.
1001 Fannin Street, Suite 2020
Houston, Texas 77002

IN WITNESS WHEREOF, the undersigned has executed this Certificate of Limited Partnership as of the date first written above.

Black Stone Natural Resources, L.L.C.,
as its general partner

By: ______________________
Name: Steve Putman
Title: Senior Vice President, General Counsel, and Secretary

State of Delaware
Secretary of State
Division of Corporations
Delivered 12:16 PM 09/16/2014
FILED 12:16 PM 09/16/2014
SRV 141183001 – 5603974 FILE

Exhibit 99.1

PRESSLER PETROLEUM CONSULTANTS, INC.
500 DALLAS, SUITE 2920
HOUSTON, TEXAS 77002

TELEPHONE
713-659-8300

FACSIMILE
713-659-6909

September 10, 2014

Black Stone Minerals Company, L.P.
1001 Fannin, Suite 2020
Houston, Texas 77002

Attn: Mr. Marc Carroll

Dear Mr. Carroll,

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2013, relating to the Black Stone Minerals Company, L.P. ("BSMC, LP") consolidated interest in certain oil and gas properties located in the United States. We understand the consolidated interest includes 100% of the interest of partnerships in which BSMC LP owns an interest. We completed our evaluation around the effective date of December 31, 2013, and this is a re-statement of that work using U.S. Securities and Exchange Commission ("SEC") guidelines. The estimates in this report have been prepared in accordance with the definitions and regulation of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities – Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for use by BSMC, LP and its affiliates in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the BSMC, LP consolidated interest in these properties as of December 31, 2013 to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth At 10%
Proved Developed Producing	16,869	229,318	$2,105,441	$1,090,214
Proved Developed Non-Producing	420	3,459	$ 46,981	$ 30,502
Proved Undeveloped	1,659	7,183	$ 125,460	$ 64,894
Total Proved	18,949	239,960	$2,277,882	$1,185,610

The oil volumes shown include crude oil and condensate and are expressed in thousands of barrels ("MBBL"); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet ("MMCF") at standard temperature and pressure bases.

The estimates shown in this report are proved reserves. Estimates of proved developed non-producing and proved undeveloped reserves have only been included for properties that are economically producible based on the constant prices and costs discussed in subsequent paragraphs of this letter. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves sub categorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Company future gross revenue is BSMC, LP consolidated interest's share of the revenue from the properties prior to any deductions. Future net revenue is after deductions for BSMC, LP consolidated interest's share of production taxes, ad valorem taxes, capital costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month un-weighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2013. For oil volumes, the average WTI Cushing, Oklahoma Spot crude price of $96.78 per barrel is used for all the properties. These average prices are adjusted for quality, transportation fees, and regional price differentials. For gas volumes, the average Henry Hub price of $3.67 per MMBTU is adjusted for energy content transportation fees, and regional price differentials. Additionally, natural gas liquid ("NGL") volumes are not calculated separately because available data is insufficient to be able to do so with accuracy, therefore, gas prices are adjusted to account for NGL revenue for properties from which NGL volumes are actually recovered and sold separately. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $94.84 per barrel of oil and $3.74 per MCF of gas.

Operating costs used in this report are based on operating expense records of BSMC, LP. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels since essentially all the properties are non-operated. Operating costs have been divided into per-well costs and per-unit-of-production costs and are not escalated for inflation.

Capital costs used in this report were provided by BSMC, LP and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs and corresponding net salvage value are not included in this report; however, these items may be necessary for a calculation of the standardized measure pursuant to FASB Accounting Standards Codification Topic 932, *Extractive Activities — Oil and Gas*.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from over-delivery or under-delivery to the BSMC, LP consolidated interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on BSMC, LP receiving its net revenue interest share of estimated future gross production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geosciences data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received from the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (“SPE Standards”). We used standard engineering methods, or used a combination of methods, including performance analysis, volumetric analysis, and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geosciences data; therefore, our conclusions necessarily represent only informed professional judgment

Ownership information was accepted as presented by BSMC, LP.

The data used in our estimates was obtained from BSMC, LP, public data sources, and the non-confidential files of various operators of the properties and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers in accordance with the SPE Standards. We do not own an interest in these properties nor are we employed on a contingent basis. During the past year, we have performed other petroleum engineering consulting services for BSMC, LP, similar to services normally rendered by the petroleum engineering profession, related to reserves evaluation of assets under consideration for potential acquisition by BSMC, LP.

Sincerely,

Pressler Petroleum Consultants, Inc.

Jim R. McReynolds, P. E.
Registration #73027

Pressler Petroleum Consultants, Inc.
Registration #7807

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) Acquisition of properties. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of Interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) Bitumen. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) Condensate. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves—Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves—Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of dulling a new well.

(7) Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) Development project. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or “G&G” costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) Exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

(15) Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) Oil and gas producing activities.

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a “terminal point”, which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term saleable hydrocarbons means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) Probabilistic estimate. The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) Proved area. The part of a property to which proved reserves have been specifically attributed.

(22) Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) Proved properties. Properties with proved reserves.

(24) Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

- *a.* *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
- *b.* *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

- *a.* *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*
- *b.* *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred indeveloping and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*
- *c.* *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*
- *d.* *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*
- *e.* *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
- *f.* *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) Resources. Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) Service well. A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells Include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) Stratigraphic test well. A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if not drilled in a known area or “development type” if drilled in a known area.

(31) Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

- (i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
- (ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*
- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by Internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined In paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) Unproved properties. Properties with no proved reserves.