Filed Pursuant to Rule 424(a)
Registration No. 333-198129

The information in this preliminary prospectus is not complete and may be changed. We may not sell these securities until the registration 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 September 15, 2014

PROSPECTUS

Viper Energy Partners LP

3,500,000 Common Units
Representing Limited Partner Interests

Viper Energy Partners LP is offering 3,500,000 common units representing limited partner interests. Our common units are listed on the NASDAQ Global Select Market under the symbol "VNOM." On September 12, 2014, the last reported sale price of our common units on the NASDAQ Global Select Market was $30.06 per common unit.

Investing in our common units involves risks. Please read "Risk Factors" beginning on page 16.

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.
- 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 two operators for substantially all of the development and production on the properties underlying our mineral interests. Substantially all of our revenue is derived from royalty payments made by these operators. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of either operator to adequately and efficiently develop and operate our acreage could have an adverse effect on our expected growth and our results of operations.
- Diamondback owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including Diamondback, have conflicts of interest with us and limited duties, and they may favor their own interests to the detriment of us and our unitholders.
- Neither we nor our general partner have any employees and we will rely solely on the employees of Diamondback to manage our business. The management team of Diamondback, which includes the individuals who will manage us, will also perform similar services for itself and will own and operate its own assets, and thus will not be solely focused on our business.
- Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.
- 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 you could be substantially reduced.
- Even if you do not receive any cash distributions from us, you will be required to pay taxes on your share of our taxable income.

In addition, we qualify as an "emerging growth company" as defined in Section 2(a)(19) of 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(1)	$	$
Proceeds to Viper Energy Partners LP (before expenses)	$	$

(1) Please read "Underwriting" for a description of all underwriting compensation payable in connection with this offering.

The underwriters may purchase up to an additional 525,000 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.

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

Joint Book-Running Managers

Barclays **Credit Suisse** **Wells Fargo Securities**

Prospectus dated , 2014

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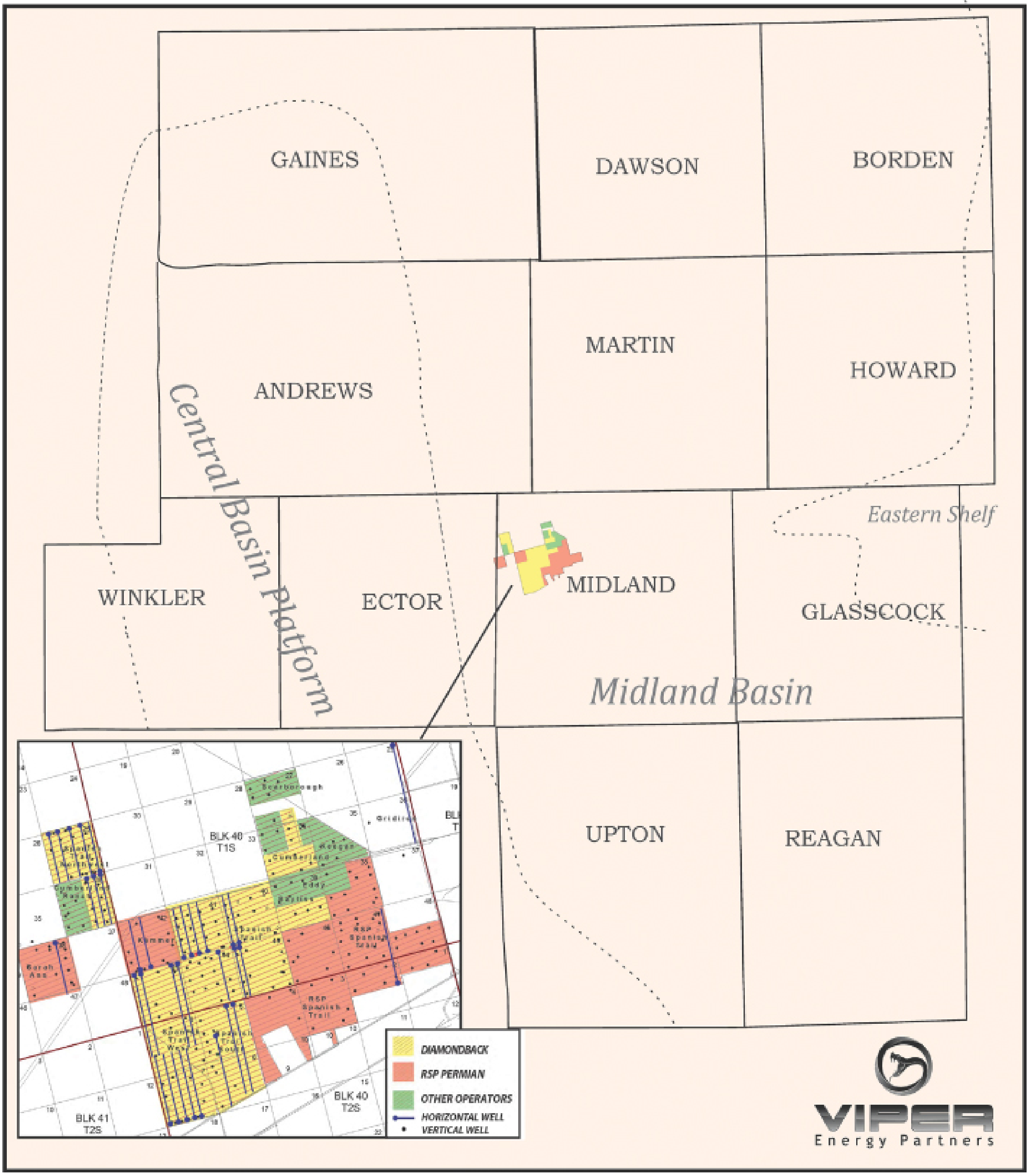

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You should rely only on the information contained in this prospectus, any free writing prospectus prepared by or on behalf of us or any other information to which we have referred you in connection with this offering. We have not, and the underwriters 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 and industry publications and surveys. Our internal research and forecasts are based on management's understanding of industry conditions, and such 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.

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 financial statements and the notes to those financial statements, before investing in our common units. The information presented in this prospectus assumes, unless otherwise indicated, that the underwriters' option to purchase additional common units is not exercised. You should read "Risk Factors" for information about important risks that you should consider before buying our common units.

References in this prospectus to "Viper Energy Partners LP Predecessor," "our predecessor," "we," "our," "us" or like terms when used in a historical context refer to Viper Energy Partners LLC, which Diamondback Energy, Inc. (NasdaqGS: FANG) contributed to Viper Energy Partners LP in connection with Viper Energy Partners LP's initial public offering (the "IPO") on June 23, 2014. When used in the present tense or prospectively, "we," "our," "us" or like terms refer to Viper Energy Partners LP and its subsidiaries. Except where expressly noted otherwise, references in this prospectus to "Diamondback" refer to Diamondback Energy, Inc. and its subsidiaries other than Viper Energy Partners LP and its subsidiaries. References in this prospectus to "our general partner" refer to Viper Energy Partners GP LLC, a wholly owned subsidiary of Diamondback Energy, Inc. References in this prospectus to "Wexford" refer to Wexford Capital LP, which is a Greenwich, Connecticut-based SEC-registered investment advisor with approximately $4.0 billion under management as of June 30, 2014. References in this prospectus to "our executive officers" and "our directors" refer to the executive officers and directors of our general partner, respectively. We include a glossary of some of the terms used in this prospectus as Appendix A.

Viper Energy Partners LP

Overview

We are a Delaware limited partnership formed by Diamondback to own, acquire and exploit oil and natural gas properties in North America. Our primary business objective is to provide an attractive return to unitholders by focusing on business results, maximizing distributions through organic growth and pursuing accretive growth opportunities through acquisitions of mineral interests from Diamondback and from third parties. Our initial assets consisted of mineral interests in oil and natural gas properties in the Permian Basin in West Texas, substantially all of which are leased to working interest owners who bear the costs of operation and development. Diamondback contributed these assets, which it acquired in September 2013 from a third party for cash, to us upon the closing of our IPO on June 23, 2014.

Like Diamondback, we are currently focused primarily on oil and natural gas properties in the Permian Basin, which is one of the oldest and most prolific producing basins in North America. The Permian Basin, which consists of approximately 85,000 square miles centered around Midland, Texas, has been a significant source of oil production since the 1920s. The Permian Basin is known to have a number of zones of oil and natural gas bearing rock throughout. However, because of the nature of the rock in many of the potentially productive zones, historically it was not economic to exploit these zones. As a result, exploration and development was limited until recently when higher oil prices and more advanced completion techniques, including hydraulic fracturing, changed the economics of drilling and development of these zones and greatly increased the oil and natural gas industry's interest in the Permian Basin. Oil production in the Permian Basin has grown from 850,000 barrels per day in 2008 to 1.3 million barrels per day in 2013. Based on public statements made by a number of publicly traded oil and natural gas companies, and the successful horizontal well results of the industry, we believe that drilling activity in the Permian Basin is likely to continue to grow at least for several more years.

Diamondback is a publicly traded independent oil and natural gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin. Diamondback owns and controls our general partner and, prior to the completion of this offering, owns approximately 92% of our outstanding common units. Diamondback's total net acreage position in the Permian Basin (including the acreage underlying our mineral interests with respect to which it is operator) was approximately 72,300 net acres at June 30, 2014, and it serves as the operator of approximately 99% of its leased acreage. As of December 31, 2013, Diamondback had estimated proved oil and natural gas reserves of 63,586 MBOE (including the estimated proved reserves associated with our mineral interests) based on a reserve report prepared by Ryder Scott Company, L.P. ("Ryder Scott"). Of these reserves, approximately 45% were classified as proved developed producing ("PDP") reserves and approximately 67% were oil, 17% were natural gas liquids and 16% were natural gas. Proved undeveloped ("PUD") reserves included in this estimate are from 206 vertical gross (151 net) well locations on 40-acre spacing and 43 gross (31 net) horizontal well locations. We believe that the properties held by Diamondback include properties that have, or with additional development will have, production and reserves characteristics that could make them attractive for inclusion in our partnership. We believe Diamondback's significant ownership interest in us will motivate it to offer additional mineral and other interests in oil and natural gas properties to us in the future, although Diamondback has no obligation to do so. Please read "—Our Relationship with Diamondback."

Our Properties

Our initial assets consisted of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin, approximately 55% of which are operated by Diamondback. Diamondback acquired the mineral interests for $440 million on September 19, 2013. The mineral interests entitle us to receive an average 21.4% royalty interest on all production from this acreage with no additional future capital or operating expense required. As of June 30, 2014, there were 218 vertical wells and 30 horizontal wells producing on this acreage, and average net production was approximately 2,414 net BOE/d during June 2014. In addition, there were six vertical wells and 17 horizontal wells in various stages of completion. For the six months ended June 30, 2014 and the period from our inception (September 18, 2013) to December 31, 2013, royalty revenue generated from these mineral interests was $33.1 million and $15.0 million, respectively.

The estimated proved oil and natural gas reserves of our initial assets, as of December 31, 2013, were 10,270 MBOE based on a reserve report prepared by Ryder Scott, our independent reserve engineer. Of these reserves, approximately 48% were classified as PDP reserves. PUD reserves included in this estimate were from 106 vertical gross well locations on 40-acre spacing and 24 gross horizontal well locations. As of December 31, 2013, our proved reserves were approximately 70% oil, 11% natural gas liquids and 18% natural gas.

Based on Diamondback's evaluation of applicable geologic and engineering data as of June 30, 2014, with respect to the approximate 55% of our mineral interests for which it is the operator, Diamondback had 68 identified potential vertical drilling locations on 40-acre spacing and an additional 184 identified potential vertical drilling locations based on 20-acre downspacing. As of such date, Diamondback had also identified 313 potential horizontal drilling locations in multiple horizons on our acreage. We do not have potential drilling location information with respect to the portion of our properties not operated by Diamondback, although we believe that such portion has very similar production characteristics to the portion operated by Diamondback. The operator of a majority of our properties not operated by Diamondback is RSP Permian, Inc. (NYSE: RSPP), an unaffiliated entity ("RSP Permian"). Diamondback has advised us that it believes it has a good relationship with RSP Permian and that it shares, on occasion, drilling and production information with RSP Permian in order to encourage further development of our properties. Additionally, Diamondback has participated with RSP Permian in the drilling and completion of five horizontal wells on shared acreage subject to our mineral interests.

The gross estimated ultimate recoveries ("EURs") from the future PUD vertical wells included in our reserve report on 40-acre spacing, as estimated by Ryder Scott as of December 31, 2013, range from 104 MBOE per well, consisting of 80 MBbls of oil and 148 MMcf of natural gas, to 146 MBOE per well, consisting of 112 MBbls of oil and 208 MMcf of natural gas, with an average EUR per well of 134 MBOE, consisting of 102 MBbls of oil and 193 MMcf of natural gas. Diamondback has advised us that it currently anticipates a reduction of approximately 20% in EURs from vertical wells drilled on 20-acre spacing.

Our Relationship with Diamondback

Diamondback owns and controls our general partner and, prior to the completion of this offering, owns approximately 92% of our outstanding common units. We believe that the properties held by Diamondback include properties that have, or with additional development will have, production and reserves characteristics that could make them attractive for inclusion in our partnership. We believe Diamondback's significant ownership in us will motivate it to offer additional mineral and other interests in oil and natural gas properties to us in the future, although Diamondback has no obligation to do so and may elect to dispose of mineral and other interests in such properties without offering us the opportunities to acquire them.

We believe Diamondback views our partnership as part of its growth strategy, and we believe that Diamondback will be incentivized to pursue acquisitions jointly with us in the future. However, Diamondback will regularly evaluate acquisitions and may elect to acquire properties without offering us the opportunity to participate in such transactions. Moreover, Diamondback may not be successful in identifying potential acquisitions. Diamondback is free to act in a manner that is beneficial to its interests without regard to ours, which may include electing not to present us with acquisition or disposition opportunities. Please read "Conflicts of Interest and Fiduciary Duties."

In addition, neither we nor our subsidiaries nor our general partner has any employees. Diamondback provides management, operating and administrative services to us and our general partner. Please read "Management" and "Certain Relationships and Related Party Transactions."

Prior to October 11, 2012, Wexford beneficially owned 100% of the equity interests in Diamondback. Upon completion of Diamondback's initial public offering, Wexford beneficially owned approximately 44.4% of its common stock. As a result of the issuance of additional shares of common stock by Diamondback and sales of its common stock by affiliates of Wexford, as of August 31, 2014, Wexford beneficially owned approximately 14.4% of the common stock of Diamondback.

Business Strategies

Our primary business objective is to provide an attractive return to unitholders by focusing on business results, maximizing distributions through organic growth and pursuing accretive growth opportunities through acquisitions of mineral interests from Diamondback and from third parties. We intend to accomplish this objective by executing the following strategies:

- ***Capitalize on the development of the properties underlying our mineral interests to grow our distributions***. Our initial assets consisted of mineral interests in the Permian Basin in West Texas. We expect the production from our mineral interest will increase as Diamondback and our other operators continue to actively drill and develop our acreage. We expect to capitalize on this development, cost-free to us, and believe the resulting increase in our aggregate royalty payments will enable us to grow our distributions.
- ***Leverage our relationship with Diamondback to participate with it in acquisitions of mineral or other interests in producing properties from third parties and to increase the size and scope of our potential third-party acquisition targets***. We intend to make opportunistic acquisitions of mineral interests that have substantial oil-weighted resource potential and organic growth potential. Diamondback was formed in part to acquire and develop oil and natural gas properties, some of which will likely meet our acquisition criteria. In addition, Diamondback's executives have long histories of evaluating, pursuing

and consummating oil and natural gas property acquisitions in North America. Through our relationships with Diamondback and its affiliates, we have access to their significant pool of management talent and industry relationships, which we believe provide us with a competitive advantage in pursuing potential third-party acquisition opportunities. We may have additional opportunities to work jointly with Diamondback to pursue certain acquisitions of mineral or other interests in oil and natural gas properties from third parties. For example, we and Diamondback may jointly pursue an acquisition where we would acquire mineral or other interests in properties and Diamondback would acquire the remaining working and revenue interests in such properties. We believe this arrangement may give us access to third-party acquisition opportunities that we would not otherwise be in a position to pursue.

- ***Seek to acquire from Diamondback, from time to time, mineral or other interests in producing oil and natural gas properties that meet our acquisition criteria***. We may have additional opportunities to acquire mineral or other interests in producing oil and natural gas properties directly from Diamondback or third parties from time to time in the future. We believe Diamondback may be incentivized to sell properties to us, as doing so may enhance Diamondback's economic returns by monetizing long-lived producing properties while potentially retaining a portion of the resulting cash flow through distributions on Diamondback's limited partner interests in us. However, none of Diamondback or any of its affiliates is contractually obligated to offer or sell any interests in properties to us.

Competitive Strengths

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

- ***Oil rich resource base in one of North America's leading resource plays***. All of the acreage underlying our mineral interests is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. The majority of our current properties are well positioned in the core of the Wolfberry play. Production on our properties for the six months ended June 30, 2014 was approximately 77% oil, 14% natural gas liquids and 9% natural gas. As of December 31, 2013, our estimated net proved reserves were comprised of approximately 70% oil and 11% natural gas liquids, which allows us to benefit from the currently more favorable pricing of oil and natural gas liquids as compared to natural gas. We believe that we will have a strong, growing production profile driven by Diamondback, a growth-oriented operator.
- ***Multi-year drilling inventory in one of North America's leading oil resource plays.*** We expect our reserves and cash available for distributions to grow organically as our operators continue to drill new wells on our acreage. Diamondback, as the operator of approximately 55% of our properties, has advised us that it has identified a multi-year inventory of potential drilling locations for our oil-weighted reserves from the acreage underlying our mineral interests. As of June 30, 2014, with respect to the approximate 55% of our properties operated by it, Diamondback had 68 identified potential vertical drilling locations based on 40-acre spacing and an additional 184 identified potential vertical drilling locations based on 20-acre downspacing. Diamondback also believes that there are a significant number of horizontal locations that could be drilled on the acreage. Based on Diamondback's initial results and those of other operators in the area to date, combined with its interpretation of various geologic and engineering data, Diamondback has identified 313 potential horizontal locations on the acreage operated by Diamondback. These locations exist across most of the acreage and in multiple horizons. Of these 313 potential locations, 121 are in the Wolfcamp B or Lower Spraberry horizons, with the remaining locations in the Wolfcamp A, Clearfork, Middle Spraberry or Cline (or Wolfcamp D) horizons. Diamondback's current potential horizontal location count is based on 660-foot spacing between wells in the Wolfcamp B and Lower Spraberry horizons in Midland County, 880-foot spacing in the Middle Spraberry horizon and 1,320-foot spacing in other horizons. The ultimate inter-well spacing may be less

than these amounts, which would result in a higher location count. Based on horizontal wells drilled to date, Ryder Scott assigned reserves to PUD locations ranging from 374 MBOE for 5,000-foot laterals in the Middle Spraberry to 847 MBOE for 10,000-foot laterals in the Wolfcamp B. When normalized to 7,500-foot laterals, Ryder Scott assigned PUD values of 638 MBOE for the Wolfcamp B horizon, 643 MBOE for the Lower Spraberry horizon and 562 MBOE for the Middle Spraberry horizon. These PUD locations, as assigned by Ryder Scott, are for direct offsets to producing wells. Based on various geologic and engineering parameters, we believe that the estimates assigned to these PUD locations are reasonable estimates for PUD locations on the remaining portion of our acreage. Additionally, we believe that there is similar potential for horizontal development on the portion of our acreage for which Diamondback is not the operator.

- ***Experienced and proven management team***. The members of our executive team have an average of over 25 years of industry experience, most of which were focused on resource play development in the Permian Basin. This team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with property acquisitions. We expect to benefit from the industry relationships fostered by the team's decades of experience in the Permian Basin. Prior to joining Diamondback, the Chief Executive Officer of our general partner held management positions at Apache Corporation, Laredo Petroleum Holdings, Inc. and Burlington Resources. The Chief Financial Officer of our general partner previously served as the Controller/Tax Director at Hiland Partners, a publicly traded master limited partnership, and has over eight years of accounting experience at other public companies. We believe the experience of our management team is essential for us to grow from our initial property base.
- ***Favorable and stable operating environment***. We will focus our growth in the Permian Basin, one of the oldest hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. With approximately 380,000 wells drilled in the Permian Basin since the 1940s, we believe that the geological and regulatory environment is more stable and predictable, and that we are faced with fewer operational risks, in the Permian Basin as compared to emerging hydrocarbon basins. We believe that the impact of the proven application of new technology, combined with the substantial geological information available about the Permian Basin, also reduces the risk of development and exploration activities as compared to emerging hydrocarbon basins.
- ***Financial flexibility to fund expansion***. We will seek to maintain financial flexibility to allow us to opportunistically purchase accretive mineral and other interests. We have entered into a revolving credit facility to be used for general partnership purposes. Please read "—Recent Developments—Credit Agreement" for further information. We believe that we have a unique distribution profile with initial distributions almost exclusively supported by mineral interests. We also expect to produce peer-leading margins unburdened by lease operating expenses.

Risk Factors

An investment in our common units involves risks. You should carefully consider 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. For more information regarding the known material risks that could impact our business, please read "Risk Factors."

Management

We are managed and operated by the board of directors and executive officers of our general partner, Viper Energy Partners GP LLC, a wholly owned subsidiary of Diamondback. As a result of owning our general partner, Diamondback has the right to appoint all members of the board of directors of our general partner, including at least three directors meeting the independence standards established by The NASDAQ Stock Market LLC ("NASDAQ") in accordance with the applicable phase-in periods under the NASDAQ rules. The board or directors of our general partner currently has six directors, two of whom are independent as defined under the independence standards of the NASDAQ Global Select Market. Our unitholders are not entitled to elect our general partner or its directors or otherwise directly participate in our management or operations. In addition, neither we nor our subsidiaries nor our general partner have any employees. Diamondback provides management, operating and administrative services to us and our general partner. Wexford provides general financial and strategic advisory services to us and our general partner pursuant to an advisory services agreement. The executive officers and some of the directors of our general partner currently serve as executive officers and directors of Diamondback. Please read "Management" and "Certain Relationships and Related Party Transactions."

Conflicts of Interest and Fiduciary Duties

Although our relationship with Diamondback may provide significant benefits to us, it may also become a source of potential conflicts. For example, Diamondback or its affiliates, including Wexford, are not restricted from competing with us. In addition, the executive officers and certain of the directors of our general partner also serve as officers or directors of Diamondback, and these officers and directors face conflicts of interest, including conflicts of interest regarding the allocation of their time between us and Diamondback.

Our general partner has a contractual duty to manage us in a manner that it believes is not adverse to our interest. However, the executive officers and directors of our general partner have fiduciary duties to manage our general partner in a manner beneficial to Diamondback, the owner of our general partner. As a result, conflicts of interest may arise in the future between us or our unitholders, on the one hand, and Diamondback and our general partner, on the other hand.

Our partnership agreement limits the liability of and replaces the fiduciary duties owed by our general partner to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions that might otherwise constitute a breach of duties by our general partner or its directors or executive officers. 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 and potential conflicts of interest 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 conflicts of interest and duties of our general partner and its directors and executive officers, please read "Conflicts of Interest and Fiduciary Duties." For a description of other relationships with our affiliates, please read "Certain Relationships and Related Party Transactions."

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 applicable generally 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;
- 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 such 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 have at least $700 million in market value of our common units held by non-affiliates, (iii) when we issue more than $1.0 billion of non-convertible debt over a three-year period or (iv) the last day of the fiscal year following the fifth anniversary of our IPO.

Recent Developments

Credit Agreement

On July 8, 2014, we entered into a secured revolving credit agreement with Wells Fargo Bank, National Association (“Wells Fargo”), as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million. As of September 2, 2014, the borrowing base was $110.0 million. We had outstanding borrowings of $78.0 million as of September 11, 2014. Please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Our Credit Agreement” for more information.

Acquisitions

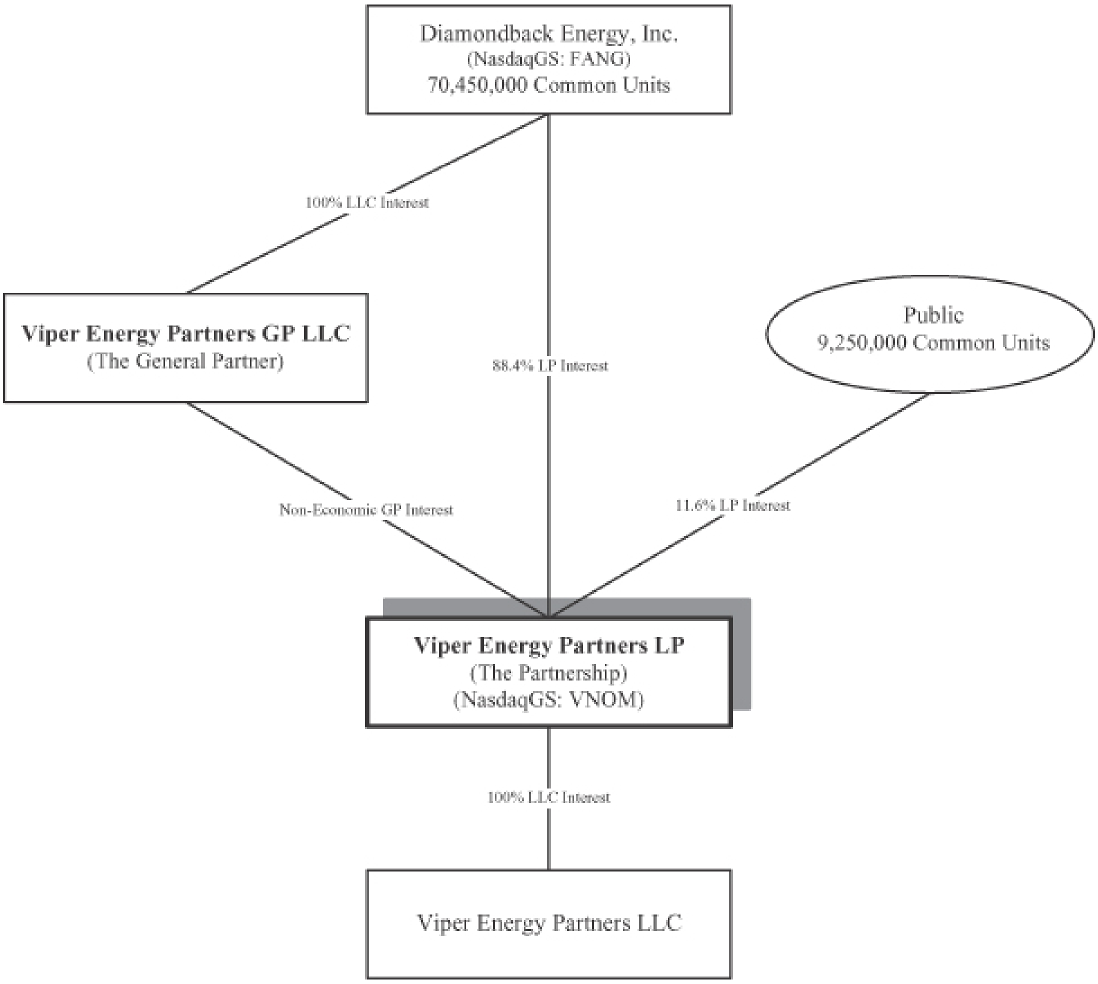
Since our IPO, we have acquired, or have entered into definitive agreements to acquire, mineral interests in an aggregate of 3,261 net acres in the Midland and Delaware basins, 179 net royalty acres in the Eagle Ford basin and a minority equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests for aggregate consideration of approximately $105.0 million in cash. During August 2014, these acquired and to be acquired interests generated estimated royalty payments and distributions of approximately $7.9 million on an annualized basis. Based on our understanding of the near term development plans for the properties underlying certain of these interests and expected production, we currently anticipate that the aggregate royalty payments and distributions from these interests will be approximately $11.7 million for calendar year 2015. While we believe that the pricing and other 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 all of these pending acquisitions are not completed and/or our assumptions are not realized, the actual royalty payments and distributions received from these interests could be substantially less than the amounts we currently estimate.

Formation Transactions and Structure

On June 23, 2014, we completed our IPO, pursuant to which we issued 5,750,000 common units at a price to the public of $26.00 per common unit. We received proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the IPO, Diamondback contributed all of the membership interests in Viper Energy Partners LLC to us in exchange for 70,450,000 common units, and our general partner maintained its non-economic general partner interest. In addition, in connection with the closing of the IPO, we agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.3 million and the net proceeds from the IPO. As of June 30, 2014, we had distributed $137.5 million to Diamondback and recorded a payable balance of approximately $11.3 million.

The following chart illustrates our organizational structure after giving effect to this offering and assumes that the underwriters do not exercise their option to purchase additional common units:



Public Common Units	9,250,000	11.6%
Interests of Diamondback:		
Common Units	70,450,000	88.4%
Non-Economic General Partner Interest	—	0%(1)
Total	79,700,000	100%

(1) Our general partner owns a non-economic general partner interest in us. Please read "How We Make Distributions—General Partner Interest."

Principal Executive Offices

Our principal executive offices are located at 500 West Texas Avenue, Suite 1200, Midland, Texas, and our telephone number is (432) 221-7400. Our website address will be *www.viperenergy.com*. We 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.

The Offering

Common units offered to the public	3,500,000 common units or 4,025,000 common units if the underwriters exercise in full their option to purchase additional common units from us.
Units outstanding after this offering	79,700,000 common units or 80,225,000 common units if the underwriters exercise in full their option to purchase additional common units from us.
Use of proceeds	We intend to use the estimated net proceeds of approximately $ million from this offering, after deducting the estimated underwriting discount and offering expenses payable by us, to repay borrowings under our credit agreement, approximately $78.0 million of which was outstanding as of September 11, 2014, and for general partnership purposes, primarily to fund pending and future acquisitions. An affiliate of Wells Fargo Securities, LLC is a lender under the credit agreement and, accordingly, will receive a portion of the net proceeds of this offering. Please read "Use of Proceeds."
Cash distributions	Within 60 days after the end of each quarter, beginning with the quarter ending September 30, 2014, we expect to make distributions to unitholders of record on the applicable record date. We expect our first distribution will consist of available cash (as described below) for the period from the closing of the IPO through September 30, 2014. In connection with the closing of the IPO, the board of directors of our general partner adopted a policy to distribute all of the available cash we generate in each quarter. Available cash for each quarter will be determined by the board of directors of our general partner following the end of such quarter. We expect that available cash for each quarter will generally equal our Adjusted EBITDA for the quarter, less cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors may determine is appropriate. 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 existing development and the discovery of new pay horizons will lead to inclining production and revenues for at least the next several years. Replacement capital expenditures are those expenditures necessary to replace our existing oil and gas reserves or otherwise maintain our asset base over the long term. We expect to seek additional acquisitions of reserves and may restrict distributions to acquire or fund such acquisitions in whole or in part. If we do not retain cash for replacement capital expenditures in amounts necessary to maintain our asset base, eventually our cash available for distribution will decrease. The board of directors of our general partner may in the future decide to withhold replacement capital expenditures from cash

	available for distribution which may have an adverse impact on the cash available for distribution in the quarter(s) in which any such amounts are withheld. To the extent that we do not withhold replacement capital expenditures in the future, a portion of our future cash available for distribution will represent a return of your capital. We do not intend to maintain excess distribution coverage for the purpose of maintaining stability or growth in our quarterly distribution or to otherwise reserve cash for distributions, and we do not intend to incur debt to pay quarterly distributions. Further, it is our intent, subject to market conditions, to finance growth capital externally, and not to reserve cash for unspecified potential future needs. Because our policy is to distribute an amount equal to all available cash we generate each quarter, our unitholders have direct exposure to fluctuations in the amount of cash generated by our business. We expect that the amount of our quarterly distributions, if any, will vary based on our earnings during each quarter. As a result, our quarterly distributions, if any, will not be stable and will vary from quarter to quarter as a direct result of variations in, among other factors, (i) the performance of our operators, (ii) earnings caused by, among other things, fluctuations in the price of oil and natural gas, changes to working capital or capital expenditures and (iii) cash reserves deemed appropriate by the board of directors of our general partner. Such variations in the amount of our quarterly distributions may be significant and could result in no distribution for any quarter. We will not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time. The board of directors of our general partner may change our distribution policy at any time. Our partnership agreement does not require us to pay distributions to our unitholders on a quarterly or other basis.
Subordinated units	None.
Incentive distribution rights	None.
Issuance of additional units	Our partnership agreement authorizes us to issue an unlimited number of additional units without the approval of our unitholders. Please read “Units Eligible for Future Sale” and “The Partnership Agreement—Issuance of Additional Partnership Interests.”
Limited voting rights	Our general partner manages and operates us. Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business. Our unitholders have no right to elect our general partner or its directors on an annual or other continuing basis. Our general partner may not be removed except by a vote of the unitholders holding at least 66 $^{2}/_{3}$% of the outstanding units, including any units owned by our general partner and its affiliates, voting together as a single class. Upon the

	consummation of this offering, Diamondback will own an aggregate of 88.4% of our common units (or 87.8% of our common units, if the underwriters exercise their option to purchase additional common units in full). This effectively gives Diamondback the ability to prevent the removal of our general partner. Please read "The Partnership Agreement—Voting Rights."
Limited call right	If at any time our general partner and its affiliates (including Diamondback) own more than 97% of the outstanding common units, our general partner will have the right, but not the obligation, to purchase all of the remaining common units at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. If our general partner and its affiliates (including Diamondback) reduce their ownership to below 75% of the outstanding common units, the ownership threshold to exercise the call right will be permanently reduced to 80%. Please read "The Partnership Agreement—Limited Call Right."
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, 2017, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately 60% 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	Our common units are listed on the NASDAQ Global Select Market under the symbol "VNOM."

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Summary Historical Financial Data

Viper Energy Partners LP was formed in February 2014 and did not own any assets prior to June 17, 2014, the date Viper Energy Partners, LLC, the then-subsidiary of Diamondback, was contributed to Viper Energy Partners LP. We refer to Viper Energy Partners, LLC as "Viper Energy Partners LP Predecessor." Viper Energy Partners LP Predecessor acquired its assets on September 19, 2013.

The contribution of Viper Energy Partners LP Predecessor to Viper Energy Partners LP was accounted for as a combination of entities under common control. Therefore, the following table presents the historical financial data of Viper Energy Partners LP as if Viper Energy Partners LP Predecessor and Viper Energy Partners LP were combined since inception.

The summary historical financial data presented as of the dates and for the periods indicated are derived from the audited and unaudited historical financial statements of Viper Energy Partners LP included elsewhere in this prospectus.

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 the audited historical financial statements of Viper Energy Partners LP and the unaudited historical financial statements of Viper Energy Partners LP 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.

	Six Months Ended June 30, 2014 (unaudited)	Period From Inception (September 18, 2013) Through December 31, 2013
	(in thousands)	
Statement of Operations Data:		
Royalty income	$ 33,102	$ 14,987
Expenditures:		
Production and ad valorem taxes	2,313	972
Depletion	11,631	5,199
General and administrative expenses	285	—
General and administrative expenses—related party	156	87
Interest expense—related party, net of capitalized interest	10,755	5,741
Total expenditures	25,140	11,999
Net income	$ 7,962	$ 2,988
Statement of Cash Flow Data:		
Net cash provided by (used in):		
Operating activities	$ 14,064	$ 4,845
Investing activities	(5,275)	(4,083)
Financing activities	(2,522)	—
Other Financial Data:		
Adjusted EBITDA(1)	$ 30,348	$ 13,928
Balance Sheet Data (at period end):		
Cash and cash equivalents	$ 7,029	$ 762
Total assets	450,692	453,023
Total liabilities	14,021	450,035
Unitholders' equity/Members' equity	436,671	2,988

(1) For more information, please read "—Non-GAAP Financial Measure" below.

Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies.

We define Adjusted EBITDA as net income (loss) before income taxes, gain/loss on derivative instruments, interest expense, depreciation, depletion and amortization, impairment of oil and gas properties, non-cash equity based compensation and asset retirement obligation accretion expense. Adjusted EBITDA is not a measure of net income (loss) as determined by United States' generally accepted accounting principles ("GAAP"). We believe Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. Our computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies.

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

	Six Months Ended June 30, 2014	Period From Inception (September 18, 2013) Through December 31, 2013
	(unaudited)	
	(in thousands)	
Net income	$ 7,962	$ 2,988
Interest expense—related party, net of capitalized interest	10,755	5,741
Depletion	11,631	5,199
Adjusted EBITDA	$ 30,348	$ 13,928

Summary Reserve Data

The following table sets forth estimates of our net proved oil and natural gas reserves as of December 31, 2013 based on a reserve report prepared by Ryder Scott. The reserve report was prepared in accordance with the rules and regulations of the SEC. You should refer to "Risk Factors," "Business—Oil and Natural Gas Data—Proved Reserves," "Business—Oil and Natural Gas Production Prices and Production Costs—Production and Price History," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our audited financial statements and notes thereto included herein in evaluating the material presented below.

	As of December 31, 2013
Estimated proved developed reserves:	
Oil (Bbls)	3,692,207
Natural gas (Mcf)	6,280,409
Natural gas liquids (Bbls)	609,303
Total (BOE)	5,348,245
Estimated proved undeveloped reserves:	
Oil (Bbls)	3,525,873
Natural gas (Mcf)	4,981,176
Natural gas liquids (Bbls)	565,820
Total (BOE)	4,921,889
Estimated Net Proved Reserves:	
Oil (Bbls)	7,218,080
Natural gas (Mcf)	11,261,585
Natural gas liquids (Bbls)	1,175,123
Total (BOE)(1)	10,270,135
Percent proved developed	52.1%

(1) 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 revised SEC guidelines applicable to reserve estimates as of the end of such periods. The unweighted arithmetic average first day of the month prices were $92.64 per Bbl for oil, $38.45 per Bbl for NGLs and $5.03 per Mcf for natural gas at December 31, 2013. 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.

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. Furthermore, our partnership agreement does not require us to pay distributions on a quarterly basis or otherwise. The amount of cash we have to distribute each quarter principally depends upon the amount of royalty revenues we generate, which are dependent upon the prices that our operators realize from the sale of oil and natural gas. In addition, the actual amount of cash we will have to distribute each quarter under the cash distribution policy that the board of directors of our general partner will adopt will be reduced by replacement capital expenditures, payments in respect of debt service and other contractual obligations and fixed charges and increases in reserves for future operating or capital needs that the board of directors may determine is appropriate.

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."

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flow and not solely on 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.

Our business is difficult to evaluate because we have a limited operating history.

Viper Energy Partners LP was formed in February 2014. In September 2013, our predecessor acquired the mineral interests contributed to us upon the consummation of the IPO. Moreover, we do not have historical financial statements with respect to the mineral interests for periods prior to their acquisition by Diamondback in September 2013. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

The amount of our quarterly cash distributions, if any, may vary significantly both quarterly and annually and is directly dependent on the performance of our business. We do 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 do 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 unitholders will vary significantly from quarter to quarter and may be zero.

The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion, including in such a manner that would result in an elimination of cash distributions regardless of the amount of available cash we generate. Our partnership agreement does not require us to make any distributions at all.

The board of directors of our general partner has adopted a cash distribution policy pursuant to which we will distribute all of the available cash we generate each quarter to unitholders of record on a pro rata basis. However, the board may change such policy at any time at its discretion and could elect not to make distributions for one or more quarters regardless of the amount of available cash we generate. Our partnership agreement does not require us to make any distributions at all. Accordingly, investors are cautioned not to place undue reliance on the permanence of such 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 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 oil and natural gas;
- the level of prices and 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 countries, 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;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- 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 posted 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 $34.03 per barrel, or Bbl, in February 2009 to a high of $113.39 per Bbl in April 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 April 2012 to a high of $7.51 per MMBtu in January 2010. 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 December 31, 2013, the West Texas Intermediate posted price for crude oil was $98.17 per Bbl and the Henry Hub spot market price of natural gas was $4.31 per MMBtu. On June 30, 2014, the West Texas Intermediate posted 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 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.

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 having to make substantial downward adjustments to our estimated proved reserves. 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.

We do not enter into hedging arrangements with respect to the oil and natural gas production from our properties, and we will be exposed to the impact of decreases in the price of oil and natural gas.

We have not entered into hedging arrangements to establish, in advance, a price for the sale of the oil and natural gas produced from our properties, and we do not intend to enter into such arrangements in the future. As a result, we may realize the benefit of any short-term increase in the price of oil and natural gas, but we will not be protected against decreases in price, and if the price of oil and natural gas decreases significantly, our business, results of operation and cash available for distribution may be materially adversely affected.

We depend on two operators for substantially all of the development and production on the properties underlying our mineral interests. Substantially all of our revenue is derived from royalty payments made by these operators. A reduction in the expected number of wells to be drilled on our acreage by these operators or the failure of either operator to adequately and efficiently develop and operate our acreage could have an adverse effect on our expected growth and our results of operations.

Our sole assets are mineral interests from which we derive royalty income. For the six months ended June 30, 2014, we received approximately 75% and 23% of our royalty revenue from Diamondback and RSP Permian, respectively. The failure of Diamondback or RSP Permian 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. Further, none of the operators of our properties are obligated to undertake any development activities, so any development and production activities will be subject to their reasonable discretion. Either or both of

Diamondback and RSP Permian 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 timing and amount of capital expenditures by our operators, which could be significantly more than anticipated;
- the ability of our operators to access capital;
- 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 sale of production; and
- the rate of production of the reserves.

The operators may elect not to undertake development activities, or may undertake such activities in an unanticipated fashion, which may result in significant fluctuations in our royalty revenues and cash available for distribution to our unitholders. If reductions in production by the operators are implemented on our properties and sustained, our revenues may also be substantially affected. Additionally, if an operator were to experience financial difficulty, the operator might not be able to pay its royalty payments or continue its operations, which could have a material adverse impact on us.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 47.9% of our total estimated proved reserves as of December 31, 2013 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve report of our independent petroleum engineer assume that substantial capital expenditures are required to develop such 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 such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such 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.

We may not be able to terminate our leases if any of our operators declare bankruptcy, and we may experience delays and be unable to replace operators that do not make royalty payments.

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 bankruptcy proceedings that could prevent the execution of a new lease or the assignment of the existing lease to another operator. In addition, if we enter into a new lease, 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.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

All of our producing properties are geographically concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our properties, they could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations and cash available for distribution.

In addition to the geographic concentration of our producing properties described above, as of June 30, 2014, all of our proved reserves were attributable to the Wolfberry play. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause our operators to permanently or temporarily shut-in all wells within a field.

Our future success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that successful exploration or development activities are conducted on our properties or we acquire properties containing proved reserves, or both. To increase reserves and production, we would need to undertake development, exploration and other replacement activities or use third parties to accomplish these activities. Substantial capital expenditures will be necessary for the development, production, exploration and acquisition of oil and natural gas reserves. Neither we nor our third-party operators may have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and efforts to drill productive wells at low finding and development costs may be unsuccessful. In addition, we do not expect to initially retain cash from our operations for replacement capital expenditures. Furthermore, although our revenues and cash available for distribution may increase if prevailing oil and natural gas prices increase significantly, finding costs for additional reserves could also increase.

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

There is intense competition for acquisition opportunities in our industry. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- 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, 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. Unless our operators further develop our existing properties, we will depend on acquisitions to grow our reserves, production and cash flow.

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 debt and equity financing and, in some cases, regulatory approvals. Further, these acquisitions may be in geographic regions in which we do not currently hold properties, which could result in unforeseen operating difficulties. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. 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 such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

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.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

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. During the six months ended June 30, 2014, Diamondback, which is the operator for 55% of the acreage associated with our properties, drilled a total of 31 gross wells and participated in two additional gross non-operated wells, of which

14 wells were completed as producing wells and 19 wells were in various stages of completion. 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 materially affected.

Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.

We account for oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $27.95 and $27.53 for the six months ended June 30, 2014 and for the period from inception (September 18, 2013) through December 31, 2013, respectively.

The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment, exceed the discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. We use the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date in estimating discounted future net revenues.

No impairment on proved oil and natural gas properties was recorded for the six months ended June 30, 2014 and for the period from inception (September 18, 2013) through December 31, 2013. We may, however, experience ceiling test write downs in the future. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Method of Accounting for Oil and Natural Gas Properties.”

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 Ryder Scott, an independent petroleum engineering firm, which conducted a well-by-well review of all our properties for the period covered by its reserve report using information provided by us. 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, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of future net cash flows. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. 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 revised SEC guidelines applicable to reserve estimates for such period. 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.

SEC rules could limit our ability to book additional proved undeveloped reserves in the future.

SEC rules require that, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional proved undeveloped reserves as our operators pursue their drilling programs. Moreover, we may be required to write down our proved undeveloped reserves if those wells are not drilled within the required five-year timeframe.

Declining general economic, business or industry conditions may have a material adverse effect on our results of operations, financial condition and cash available for distribution.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the United States mortgage market and a weak real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and natural gas liquids from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations, financial condition and cash available for distribution.

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, including the Chief Executive Officer of our general partner, Travis D. Stice, could disrupt our business. Diamondback has employment agreements with Travis D. Stice and Teresa L. Dick, the Chief Financial Officer of our general partner, which contain restrictions on competition with the business or operations of Diamondback and its subsidiaries until the later of the termination of their employment with or other affiliation with such entities and for a period of six months thereafter. However, as a practical matter, such employment agreements may not assure the retention of Diamondback’s employees. 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.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to succeed.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. 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. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional 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. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Our credit agreement has restrictions and financial covenants that may restrict our business and financing activities and our ability to pay distributions to our unitholders.

The operating and financial restrictions and covenants in our credit agreement and any future financing agreements may restrict our ability to finance future operations or capital needs or to engage, expand or pursue our business activities or to pay distributions to our unitholders. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations.” Our future ability to comply with these restrictions and covenants is uncertain and will be affected by the levels of cash flow from our operations and other events or circumstances beyond our control. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any provisions of our credit agreement that are not cured or waived within the appropriate time periods provided in our credit agreement, a significant portion of our indebtedness may become immediately due and payable, our ability to make distributions to our unitholders will be inhibited and our lenders’ commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. In addition, our obligations under our credit agreement are secured by substantially all of our assets, and if we are unable to repay our indebtedness under our credit agreement, the lenders could seek to foreclose on our assets.

Our credit agreement allows us to borrow in an amount up to the borrowing base, which is based on our oil and natural gas reserves and other factors as determined semi-annually by our lenders in their sole discretion. A future decline in commodity prices could result in a redetermination that lowers our borrowing base at that time and, in such case, we could be required to repay any indebtedness outstanding in excess of the borrowing base. If we are unable to repay any borrowings in excess of a decreased borrowing base, we would be in default and no longer able to make any distributions to our unitholders.

Loss of our information and computer systems could adversely affect our business.

We are dependent on our information systems and computer based programs. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Risks Related to Operators and Other Working Interest Owners

The following risks describe risks that may directly affect our business and operations to the extent we elect in the future to engage in the exploration, development and production of oil and natural gas properties. In addition, any operators of our properties, including our current operators, are subject to the risks and *uncertainties described below, and, as the owner of mineral interests, we are indirectly exposed to the same risks and uncertainties. For purposes of this section, where applicable, references to "we," "us" and "our" refer to Viper Energy Partners LP to the extent the partnership were to acquire working interests in the future, as well as to any operators of our properties, including the current operators.*

If a significant portion of any future net leasehold acreage is undeveloped, and that acreage is not ultimately developed or does not become commercially productive, we could lose rights under these leases, and any such events could have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our financial condition, results of operations and cash available for distribution.

To the extent we acquire working interests in the future, or 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, we could lose our rights under those leases if we do not timely develop such acreage. In addition, if we are required under any such oil and natural gas leases to drill wells that are commercially productive and we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our financial condition, results of operations and cash available for distribution may be highly dependent on successfully developing our undeveloped leasehold acreage.

Development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. To the extent we acquire working interests in the future, we will not be able to assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we acquire working interests in the future and we are unable to fund our capital requirements, we may be required to curtail operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, results of operations and cash available for distribution. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings.

We may incur losses as a result of title defects in the properties in which we invest.

If we acquire working interests in the future, when acquiring oil and natural gas leases, we may not elect to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we may rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations, financial condition and cash available for distribution.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, our business, results of operations and cash available for distribution may be adversely affected.

Identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

To the extent we acquire working interests in the future, our ability to drill and develop identified potential drilling locations will depend 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, identified potential drilling locations are typically in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. We will not be able to predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable or whether wells drilled on 20-acre downspacing will produce at the same rates as those on 40-acre spacing. The use of technologies and the study of producing fields in the same area will not enable us 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, we 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 we drill wells that we identify as dry holes in current and future drilling locations, our drilling success rate may decline and materially harm our business.

We will not be able to assure you that the analogies drawn from available data from wells drilled, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations we identify will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those identified, which could adversely affect our business.

For information on Diamondback’s identified potential drilling locations, please read “Business.”

Acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. To the extent we acquire working interests in the future, the cost to renew our leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Any reduction in our drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. Any such losses of leases could materially and adversely affect the growth of our financial condition, results of operations and cash available for distribution.

The inability of one or more of our customers to meet their obligations may adversely affect our financial condition, results of operations and cash available for distribution.

To the extent we acquire working interests in the future, we may have exposure to credit risk through receivables from joint interest owners on properties we operate and receivables from purchasers of our oil and natural gas production.

Joint interest receivables will arise from billing entities that own partial interests in any wells we operate. These entities will typically participate in our wells primarily based on their ownership in leases on which we wish to drill. We will generally be unable to control which co-owners participate in our wells.

We also may be subject to credit risk due to the concentration of oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Current economic circumstances may further increase these risks. Generally, customers are not required to post collateral. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial condition, results of operations and cash available for distribution.

To the extent we depend upon certain significant purchasers for the sale of most of our oil and natural gas production, the loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce and adversely affect our results of operations and cash available for distribution.

To the extent we acquire working interests in the future, the availability of a ready market for any oil and natural gas we produce will depend on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of natural gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of natural gas sold in interstate commerce. In addition, to the extent we depend upon certain significant purchasers for the sale of most of our oil and natural gas production, the loss of one or more of such purchasers, or their failure or inability to meet their obligations to us, could adversely affect our results of operations and cash available for distribution. We cannot assure you that we will have ready access to suitable markets for our oil and natural gas production if we acquire working interests in the future.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

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. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. To the extent we acquire working interests in the future, in accordance with customary industry practice, we will rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. In addition, we may not have long-term contracts securing the use of our rigs, and the operator of those rigs may choose to cease providing services to us. 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 exploration and development operations, which in turn could adversely affect our financial condition, results of operations and cash available for distribution.

Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash available for distribution.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. During the last two years, Texas has experienced extreme drought conditions. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. To the extent we acquire working interests in the future, if we are unable to obtain water to use in our operations from local sources, or we are unable to effectively utilize flowback water, we may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash available for distribution.

The results of our 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.

To the extent we acquire working interests in the future, our operations will involve utilizing the latest drilling and completion techniques. Risks that we will face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we will face while completing wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in identified vertical drilling locations. Furthermore, certain of the new techniques we 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 any such 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 we 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 drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as 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.

The marketability of oil and natural gas production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our results of operations and cash available for distribution could be adversely affected.

To the extent we acquire working interests in the future, the marketability of our oil and natural gas production will depend in part upon the availability, proximity and capacity of transportation facilities, including gathering systems, trucks and pipelines, owned by third parties. We may not control these third party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. For example, on certain occasions, our operators have experienced high line pressure at their tank batteries with occasional flaring due to the inability of the gas gathering systems to support the increased production of natural gas in the Permian Basin. If we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. In addition, the amount of oil and natural gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our control, such as pipeline interruptions due to maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we are provided with limited, if any, notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, could adversely affect our financial condition, results of operations and cash available for distribution.

Our operations will be subject to various governmental laws and regulations which require compliance that can be burdensome and expensive and could expose us to significant liabilities, which could adversely affect our cash available for distribution.

To the extent we acquire working interests in the future, our oil and natural gas operations will be 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 discharge permits for drilling operations, drilling bonds, reports concerning operations, 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 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 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. To the extent we acquire working interests in the future, we will be required to 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 increase capital costs on the part of operators and third party downstream natural gas transporters.

If we acquire working interests in the future, we will also be required to 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 such pipelines and with federal policies related to the use of interstate capacity.

Significant expenditures may be required 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, to the extent we acquire working interests in the future, will affect us. These and other potential regulations could increase our operating costs, reduce our liquidity, delay our operations or otherwise alter the way we conduct our business, any of which could have a material adverse effect on the amount of cash available for distribution to our unitholders.

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

To the extent we acquire working interests in the future, we expect to engage in hydraulic fracturing. Moreover, our current operators engage in 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. 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, specifically as “Class II” UIC wells. In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the 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 announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting “flowback,” as well as “produced water.” If adopted, the new pretreatment rules will require operators to pretreat wastewater before transferring it to a treatment facility that discharges to surface water. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

On August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (“VOCs”), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or “green completions” on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely responsive to some of these requests. For example, on September 23, 2013, the EPA published an amendment extending compliance dates for certain storage vessels. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 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. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, 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 and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Railroad Commission recently 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. To the extent we acquire working interests, we expect to use hydraulic fracturing extensively in connection with the development and production of our oil and natural gas properties and any increased federal, state, local, foreign or international regulation of hydraulic fracturing could reduce the volumes of oil and natural gas that we 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 and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we conduct operations, we may incur substantial costs to comply with such requirements that 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, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities 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. Such legislative changes could cause operators to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us, to the extent we acquire working interests in the future, or our operators could have a material adverse effect on our financial condition and results of operations. 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.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

To the extent we acquire working interests in the future, we may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, financial condition, results of operations and cash available for distribution could be materially adversely affected.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

To the extent we acquire working interests in the future, our operations may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

If we acquire working interests in the future, the adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In December 2009, the EPA issued an Endangerment Finding that determined that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment because, according to the EPA, emissions of such 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 under existing provisions of the federal Clean Air Act, including rules which regulate emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. 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 natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

In addition, in August 2012, the EPA established new source performance standards (“NSPS”) for volatile organic compounds and sulfur dioxide and an air toxic standard for oil and natural gas production, transmission, and storage. The rules include the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several other sources, such as storage tanks and other equipment, and limits methane emissions from these sources in an effort to reduce GHG emissions.

The EPA has continued to adopt GHG regulations of other industries, such as the September 2013 proposed GHG rule that, if finalized, would set new source performance standards for new coal-fired and natural gas-fired power plants, which could have an adverse effect on our financial condition, results of operation and cash available for distribution to the extent we acquire working interests in the future. The EPA is also considering additional regulation of greenhouse gases as "air pollutants." As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The U.S. Congress has not adopted such legislation at this time, but it may do so in the future, and many states continue to pursue regulations to reduce greenhouse gas emissions. 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 such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. In addition, substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce.

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 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 our production and increase our costs and 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 operations.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may adversely affect our business, financial condition, results of operations and cash available for distribution.

If we acquire working interests in the future, our drilling activities will be subject to many risks. For example, we will not be able to assure you that wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies used do not provide conclusive knowledge prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

- unusual or unexpected geological formations;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In the event that planned operations, including the drilling of development wells, are delayed or cancelled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition, results of operations and cash available for distribution to our unitholders may be adversely affected.

Operating hazards and uninsured risks may result in substantial losses and could adversely affect our results of operations and cash available for distribution.

To the extent we acquire working interests in the future, our operations 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, our 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 us 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.

We would endeavor to contractually allocate potential liabilities and risks between us and the parties that provide us with services and goods, which include pressure pumping and hydraulic fracturing, drilling and cementing services and tubular goods for surface, intermediate and production casing. Under agreements with our vendors, to the extent responsibility for environmental liability is allocated between the parties, (i) our vendors would generally assume all responsibility for control and removal of pollution or contamination which originates above the surface of the land and is directly associated with such vendors' equipment while in their control and (ii) we would generally assume the responsibility for control and removal of all other pollution or contamination which may occur during our operations, including pre-existing pollution and pollution which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas or other substances, as well as the use or disposition of all drilling fluids. In addition, we may agree to indemnify our vendors for loss or destruction of vendor-owned property that occurs in the well hole (except for damage that occurs when a vendor is performing work on a footage, rather than day work, basis) or as a result of the use of equipment, certain corrosive fluids, additives, chemicals or proppants. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into contractual arrangements with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition, results of operation and cash available for distribution.

In accordance with what we believe to be customary industry practice, we would expect to 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 have, 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.

If we acquire working interests in the future, we may operate in areas of high industry activity, which may make it difficult to hire, train or retain qualified personnel needed to manage and operate our assets.

If we acquire working interests in the future, our operations and drilling activity will likely be concentrated in the Permian Basin, an area in which industry activity has increased rapidly. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years due to competition and may increase substantially in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary to continue or complete development activities could lead to a reduction in production volumes. Any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our business, financial condition, results of operations and cash available for distribution.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

To the extent we acquire working interests in the future, we will rely on 2-D and 3-D seismic data. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. To the extent we acquire working interests in the future, as others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use were to become obsolete, our business, financial condition, results of operations and cash available for distribution could be materially and adversely affected.

Increased costs of capital could adversely affect our business.

Our business and operating results could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our services and causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and, to the extent we acquire working interests in the future, our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Risks Inherent in an Investment in Us

Diamondback owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including Diamondback, have conflicts of interest with us and limited duties, and they may favor their own interests to the detriment of us and our unitholders.

Diamondback owns and controls our general partner and appoints all of the directors of our general partner. All of the executive officers and certain of the directors of our general partner are also officers and/or directors of Diamondback. Although our general partner has a duty to manage us in a manner that it believes is not adverse to our interest, the executive officers and directors of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to Diamondback. Therefore, conflicts of interest may arise between Diamondback or any of its affiliates, including our general partner, on the one hand, and us or any of our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates over the interests of our common unitholders. These conflicts include the following situations, among others:

- Our general partner is allowed to take into account the interests of parties other than us, such as Diamondback, in exercising certain rights under our partnership agreement.
- Neither our partnership agreement nor any other agreement requires Diamondback to pursue a business strategy that favors us.
- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limits our general partner's liabilities and restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of cash reserves, each of which can affect the amount of cash that is distributed to our unitholders.
- Our general partner determines which costs incurred by it and its affiliates are reimbursable by us.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units.
- Our general partner controls the enforcement of obligations that it and its affiliates owe to us.

- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

In addition, Diamondback or its affiliates, including Wexford, may compete with us. Please read "—Diamondback and other affiliates of our general partner, including Wexford, may compete with us." and "Conflicts of Interest and Fiduciary Duties."

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.

The board of directors of our general partner has adopted a cash distribution policy pursuant to which we will distribute an amount equal to the available cash we generate each quarter to our unitholders. However, the board of directors of our general partner may change such 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. Accordingly, investors are cautioned not to place undue reliance on the permanence of such 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, whose interests may differ from those of our common unitholders. Our general partner has limited duties to our unitholders, which may permit it to favor its own interests or the interests of Diamondback to the detriment of our common unitholders.

The board of directors of our general partner has adopted a policy to distribute an amount equal to 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 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. As such, to the extent we are unable to finance growth externally, our distribution policy will significantly impair our ability to grow.

To the extent 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. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, would reduce the available cash that we have to distribute to our unitholders. Please read "Cash Distribution Policy and Restrictions on Distributions."

Neither we nor our general partner have any employees, and we rely solely on the employees of Diamondback to manage our business. The management team of Diamondback, which includes the individuals who manage us, also perform similar services for Diamondback and own and operate Diamondback's assets, and thus are not solely focused on our business.

Neither we nor our general partner have any employees and we rely solely on Diamondback to operate our assets and perform other management, administrative and operating services for us and our general partner. Diamondback provides similar activities with respect to its own assets and operations. Because Diamondback provides services to us that are similar to those performed for itself, Diamondback may not have sufficient human, technical and other resources to provide those services at a level that Diamondback would be able to provide to us if it were solely focused on our business and operations. Diamondback may make internal decisions on how to allocate its available resources and expertise that may not always be in our best interest compared to Diamondback's interests. There is no requirement that Diamondback favor us over itself in providing its services. If the employees of Diamondback and their affiliates do not devote sufficient attention to the management and operation of our business, our financial results may suffer and our ability to make distributions to our unitholders may be reduced.

Our partnership agreement replaces our general partner's fiduciary duties to our unitholders.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;
- whether to exercise its call right;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights; and
- whether or not to consent to any merger or consolidation of the partnership or any amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above. Please read "Conflicts of Interest and Fiduciary Duties—Fiduciary Duties."

Our partnership agreement restricts the remedies available to holders of our units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

- whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is generally required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any higher standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner and its executive officers and directors will not be liable for monetary damages or otherwise to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such losses or liabilities were the result of conduct in which our general partner or its executive officers or directors engaged in bad faith, willful misconduct or fraud or, with respect to any criminal conduct, with knowledge that such conduct was unlawful; and
- our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our limited partners if a transaction, even a transaction with an affiliate or the resolution of a conflict of interest, is:
  - (1) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval; or
  - (2) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, other than one where our general partner is permitted to act in its sole discretion, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee then it will be presumed that, in making its decision, taking any action or failing to act, the board of directors 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 such proceeding will have the burden of overcoming such presumption. Please read “Conflicts of Interest and Fiduciary Duties.”

Diamondback and other affiliates of our general partner, including Wexford, may compete with us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner, engaging in activities incidental to its ownership interest in us and providing management, advisory and administrative services to its affiliates or to other persons. However, affiliates of our general partner, including Diamondback and Wexford, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, Diamondback or Wexford may compete with us for investment opportunities and may own an interest in entities that compete with us. Further, Diamondback and its affiliates, including Wexford, may acquire, develop or dispose of additional oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets.

Diamondback is an established participant in the oil and natural gas industry and has resources greater than ours, which factors may make it more difficult for us to compete with Diamondback with respect to commercial activities as well as for potential acquisitions. As a result, competition from Diamondback and its affiliates could adversely impact our results of operations and cash available for distribution to our unitholders.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors, Diamondback and Wexford. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders. Please read “Conflicts of Interest and Fiduciary Duties.”

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management’s decisions regarding our business. Unitholders have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by Diamondback, as a result of it owning our general partner, and not by our unitholders. Please read “Management—Management of Viper Energy Partners LP” and “Certain Relationships and Related Party Transactions.” Unlike publicly traded corporations, we do not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

If our unitholders are dissatisfied with the performance of our general partner, they have limited ability to remove our general partner. Unitholders will be unable to remove our general partner without its consent because affiliates of our general partner will own sufficient units upon the completion of this offering to be able to prevent its removal. The vote of the holders of at least 66 $^{2}/_{3}$ % of all outstanding common units is required to remove our general partner. Following the closing of this offering, Diamondback will own 88.4% of our common units (or 87.8% of our common units, if the underwriters exercise their option to purchase additional common units in full).

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units (other than our general partner and its affiliates and permitted transferees).

Our partnership agreement restricts unitholders' voting rights by providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, may not vote on any matter. 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.

Cost reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce cash available for distribution to our unitholders. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on the common units, we will reimburse our general partner and its affiliates for all expenses they incur and payments they make on our behalf. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates 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 by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of cash available for distribution to our unitholders. Please read "Cash Distribution Policy and Restrictions on Distributions."

We and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford will provide general finance and advisory services in exchange for a fee and certain expense reimbursement. This fee will reduce the amount of cash available for distribution to our unitholders. In addition, we have entered into a tax sharing agreement with Diamondback pursuant to which we will reimburse Diamondback for our share of state and local income and other taxes borne by Diamondback as a result of our results being included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on the closing date of the IPO. Please read "Certain Relationships and Related Party Transactions—Agreements and Transactions with Affiliates."

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owner of our general partner to transfer its membership interests in our general partner to a third party. After any such transfer, the new member or members of our general partner would then be in a position to replace the board of directors and executive officers of our general partner with its own designees and thereby exert significant control over the decisions taken by the board of directors and executive officers of our general partner. This effectively permits a "change of control" without the vote or consent of the unitholders.

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.

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."

Our general partner has a call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates (including Diamondback) own more than 97% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (1) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. If our general partner and its affiliates (including Diamondback) reduce their ownership to below 75% of the outstanding common units, the ownership threshold to exercise the call right will be permanently reduced to 80%. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units and then exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Upon consummation of this offering, Diamondback will own 88.4% of our common units. For additional information about the limited call right, please read "The Partnership Agreement—Limited Call Right."

We may issue additional common units and other equity interests without unitholder approval, which would dilute existing unitholder ownership interests.

Under our partnership agreement, we are authorized to issue an unlimited number of additional interests, including common units, without a vote of the unitholders. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- the proportionate ownership interest of 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.

Please read "The Partnership Agreement—Issuance of Additional Partnership Interests."

There are no limitations in our partnership agreement on our ability to issue units ranking senior to the common units.

In accordance with Delaware law and the provisions of our partnership agreement, we may issue additional partnership interests that are senior to the common units in right of distribution, liquidation and voting. The issuance by us of units of senior rank may (i) reduce or eliminate the amount of cash available for distribution to our common unitholders; (ii) diminish the relative voting strength of the total common units outstanding as a class; or (iii) subordinate the claims of the common unitholders to our assets in the event of our liquidation.

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 80,225,000 common units outstanding (if the underwriters exercise in full their option to purchase additional common units from us). All of the common units held by Diamondback will be subject to resale restrictions under a 60-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 such sales might occur, could have a material adverse effect on the price of our common units or could impair our ability to obtain capital through an offering of equity securities. In addition, we have agreed to provide registration rights to Diamondback. Under our partnership agreement, our general partner and its affiliates have registration rights relating to the offer and sale of any units that they hold. Please read "Units Eligible for Future Sale."

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

Prior to the completion of our IPO in June 2014, we had 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 of 2002 and the Dodd-Frank Act of 2010, as well as rules implemented by the SEC and NASDAQ, 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 affected by our expenses, including the costs associated with being a publicly traded partnership. We estimate that we will incur approximately $2.5 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 and 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, unlike other public companies, we will not be required to, among other things, (1) 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 of 2002, (2) 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, (3) comply with any new audit rules adopted by the PCAOB after April 5, 2012 unless the SEC determines otherwise or (4) 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.

Diamondback is a publicly traded corporation and has developed a system of internal controls for compliance with public reporting requirements. However, prior to the IPO, our predecessor had not been required to file reports with the SEC on a stand-alone basis. Upon the completion of the IPO, we became subject to the public reporting requirements of the Exchange Act. 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 of 2002. 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, 2015. 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.

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

Our common units are listed on the NASDAQ Global Select Market. Because we are a publicly traded partnership, NASDAQ 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. Accordingly, unitholders do not have the same protections afforded to stockholders of certain corporations that are subject to all of NASDAQ'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 unitholder bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with such 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 most claims, suits, actions and proceedings involving us or our officers, directors and employees. In addition, if any person brings any of the aforementioned claims, suits, actions or proceedings and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such 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. Please read "The Partnership

Agreement—Applicable Law; Forum, Venue and Jurisdiction." 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 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. These provisions may have the effect of discouraging lawsuits against us and our general partner's directors and officers.

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 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 and/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 units held by any person (i) whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates chargeable to our customers, (ii) whose nationality, citizenship or related status creates substantial risk of cancellation or forfeiture of any of our property and/or (iii) who fails to comply with the procedures established to obtain such proof. 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. Please read "The Partnership Agreement—Non-Taxpaying Holders; Redemption" and "The Partnership Agreement—Non-Citizen Assignees; Redemption."

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 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 you 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 such 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 such 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 such 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 purposes, please read "Material U.S. Federal Income Tax Consequences—Partnership Status" for a further discussion.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such 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 impact 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 you do not receive any cash distributions from us, you will be required to pay taxes on your 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 such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such 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" for a further discussion of the foregoing.

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 such 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. Immediately following this offering, affiliates of Diamondback will directly and indirectly own more than % of the total interests in our capital and profits. Therefore, a transfer by affiliates of Diamondback of all or a portion of their interests in us could result in a termination of our partnership for federal income tax purposes. 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 may 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 may be treated as doing business directly or indirectly in a number of jurisdictions and many of these jurisdictions impose a personal income tax. 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. 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. 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, after deducting the estimated underwriting discount and offering expenses payable by us, to repay borrowings under our credit agreement, approximately $78.0 million of which was outstanding as of September 11, 2014, and for general partnership purposes, primarily to fund pending and future acquisitions. An affiliate of Wells Fargo Securities, LLC is a lender under the credit agreement and, accordingly, will receive a portion of the net proceeds of this offering. See “Underwriting.”

Our credit agreement matures in 2019 and bears interest at a variable rate, which was 2.16% as of September 11, 2014. The outstanding borrowings under our credit agreement were incurred to fund our recent acquisitions of mineral, overriding royalty, net profits and other similar interests and equity interests in entities that hold such interests. Please read “Summary—Recent Developments—Acquisitions.”

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CAPITALIZATION

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

- on an actual basis; and
- on an as adjusted basis to reflect this offering 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 audited historical financial statements and accompanying notes and the unaudited historical financial statements and accompanying notes included elsewhere in this prospectus. You should also read this table in conjunction with "Use of Proceeds" and "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	As of June 30, 2014	
	Actual	As Adjusted
	(in thousands)	
Cash and cash equivalents	$ 7,029	$
Long-term debt(1)	$ —	—
Unitholders' equity:		
General partner	—	—
Common units	436,671	
Total unitholders' equity	$436,671	$
Total capitalization	$436,671	$

(1) As of September 11, 2014, we had $78.0 million in aggregate principal amount outstanding under our credit agreement. We intend to use the net proceeds from this offering to repay all of these outstanding borrowings.

PRICE RANGE OF COMMON UNITS AND DISTRIBUTIONS

Our common units are listed on the NASDAQ Global Select Market under the symbol "VNOM." Our common units began trading on June 18, 2014 at an initial public offering price of $26.00 per common unit. The following table shows the low and high sales prices per common unit, as reported by the NASDAQ Global Select Market, since June 18, 2014. No distributions have been paid to date.

Period:	High	Low
Second quarter 2014 (beginning June 18, 2014)	$36.00	$31.00
Third quarter 2014 (through September 12, 2014)	$34.50	$30.00

The last reported sale price of our common units on the NASDAQ Global Select Market on September 12, 2014 was $30.06. As of September 12, 2014, there were approximately 2 holders of record of our common units.

CASH DISTRIBUTION POLICY AND RESTRICTIONS ON DISTRIBUTIONS

Cash Distribution Policy

The board of directors of our general partner has adopted a policy pursuant to which we will distribute all of the available cash we generate each quarter, beginning with the quarter ending September 30, 2014. Our first distribution, however, will include available cash for the period from the closing of the IPO through September 30, 2014. Available cash for each quarter will be determined by the board of directors of our general partner following the end of such quarter. We expect that available cash for each quarter will generally equal our Adjusted EBITDA for the quarter, less cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors may determine is appropriate. We do not intend to maintain excess distribution coverage for the purpose of maintaining stability or growth in our quarterly distribution or otherwise to reserve cash for distributions, nor do we intend to incur debt to pay quarterly distributions. Further, it is our intent, subject to market conditions, to finance growth capital externally. 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."

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 existing development and the discovery of new pay horizons will lead to inclining production and revenues for at least the next several years. Replacement capital expenditures are those expenditures necessary to replace our existing oil and gas reserves or otherwise maintain our asset base over the long term. We expect to seek additional acquisitions of reserves and may restrict distributions to acquire or fund such acquisitions in whole or in part. If we do not retain cash for replacement capital expenditures in amounts necessary to maintain our asset base, eventually our cash available for distribution will decrease. The board of directors of our general partner may in the future decide to withhold replacement capital expenditures from cash available for distribution which may have an adverse impact on the cash available for distribution in the quarter(s) in which any such amounts are withheld. To the extent that we do not withhold replacement capital expenditures in the future, a portion of our future cash available for distribution will represent a return of your capital.

Because our policy will be to distribute all available cash we generate each quarter, without reserving cash for future distributions or borrowing to pay distributions during periods of low revenue, our unitholders will have direct exposure to fluctuations in the amount of cash generated by our business. Our quarterly cash distributions, if any, will not be stable and will vary from quarter to quarter as a direct result of variations in the performance of our operators and revenue caused by fluctuations in the prices of oil and natural gas. Such variations may be significant.

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 unitholders have no contractual or other legal right to receive cash distributions from us on a quarterly or other basis. The board of directors of our general partner will adopt a policy pursuant to which we will distribute to our unitholders each quarter all 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 cash distribution policy is subject to restrictions on distributions under our credit agreement. Specifically, our credit agreement contains material financial tests and covenants that we must satisfy. These financial tests and covenants are described in this prospectus under the caption "Management's

Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Our Credit Agreement." Should we be unable to satisfy these restrictions under our credit agreements, we would be prohibited from making cash distributions to you notwithstanding our cash distribution policy.

- Our business performance may be volatile, and our cash flows may be less stable, than the business performance and cash flows of most publicly traded partnerships. As a result, our quarterly cash distributions may be volatile and may vary quarterly and annually.
- We do 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, including those held by Diamondback, will be subordinate in right of distribution payment to the common units sold in this offering.
- Our general partner has 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 set a limit on 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.
- Prior to making any distributions on our units, we will reimburse our general partner and its affiliates for all direct and indirect expenses they incur on our behalf. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us, but does not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of cash to pay distributions to our unitholders.
- 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, tax expenses, 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 and payment of our expenses. To fund growth, we will eventually need capital in excess of the amounts we may retain in our business, but we expect that our growth will depend at least initially on our operators' ability to access external expansion capital. As a result, our growth will depend initially on our operators' ability, and perhaps our ability in the future, to raise debt and equity capital from third parties in sufficient amounts and on favorable terms when needed. To the extent efforts to access capital externally are unsuccessful, our ability to grow will be significantly impaired.

We expect to pay our distributions within 60 days of the end of each quarter. Our first distribution will include available cash for the period from the closing of the IPO through September 30, 2014.

HOW WE MAKE DISTRIBUTIONS

General

Within 60 days after the end of each quarter, we expect to make distributions, as determined by the board of directors of our general partner, to unitholders of record on the applicable record date. Our first distribution will include available cash for the period from the closing of the IPO through September 30, 2014. We do not have a legal obligation to pay distributions, and the amount of distributions, if any, declared and paid under our distribution policy is determined by the board of directors of our general partner. See "Cash Distribution Policy and Restrictions on Distributions."

Method of Distributions

We intend to distribute available cash to our unitholders, pro rata. Our partnership agreement permits us to borrow to make distributions, but we are not required to, and do not intend to, borrow to pay quarterly distributions. Accordingly, there is no guarantee that we will pay any distribution on the units in any quarter.

Common Units

At the closing of this offering, we will have 79,700,000 common units outstanding. Each common unit will be entitled to receive cash distributions to the extent we distribute available cash. Common units will not accrue arrearages. Our partnership agreement allows us to issue an unlimited number of additional equity interests of equal or senior rank.

General Partner Interest

Our general partner owns a non-economic general partner interest and therefore is not entitled to receive cash distributions. However, it may acquire common units and other equity interests in the future and will be entitled to receive pro rata distributions in respect of those equity interests.

SELECTED HISTORICAL FINANCIAL DATA

Viper Energy Partners LP was formed in February 2014 and did not own any assets prior to June 17, 2014, the date Viper Energy Partners, LLC, the then-subsidiary of Diamondback, was contributed to Viper Energy Partners LP. We refer to Viper Energy Partners, LLC as "Viper Energy Partners LP Predecessor." Viper Energy Partners LP Predecessor acquired its assets on September 19, 2013.

The contribution of Viper Energy Partners LP Predecessor to Viper Energy Partners LP was accounted for as a combination of entities under common control. Therefore, the following table presents the historical financial data of Viper Energy Partners LP as if Viper Energy Partners LP Predecessor and Viper Energy Partners LP were combined since inception.

The selected historical financial data presented as of the dates and for the periods indicated are derived from the audited and unaudited historical financial statements of Viper Energy Partners LP included elsewhere in this prospectus.

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 the audited and unaudited historical financial statements of Viper Energy Partners LP 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.

	Six Months Ended June 30, 2014 (unaudited)	Period From Inception (September 18, 2013) Through December 31, 2013
	(in thousands)	
Statement of Operations Data:		
Royalty income	$ 33,102	$ 14,987
Expenditures:		
Production and ad valorem taxes	2,313	972
Depletion	11,631	5,199
General and administrative expenses	285	—
General and administrative expenses—related party	156	87
Interest expense—related party, net of capitalized interest	10,755	5,741
Total expenditures	25,140	11,999
Net income	$ 7,962	$ 2,988
Statement of Cash Flow Data:		
Net cash provided by (used in):		
Operating activities	$ 14,064	$ 4,845
Investing activities	(5,275)	(4,083)
Financing activities	(2,522)	—
Other Financial Data:		
Adjusted EBITDA(1)	$ 30,348	$ 13,928
Balance Sheet Data (at period end):		
Cash and cash equivalents	$ 7,029	$ 762
Total assets	450,692	453,023
Total liabilities	14,021	450,035
Unitholders' equity/Members' equity	436,671	2,988

(1) For more information, please read "Summary—Summary Historical Financial Data—Non-GAAP Financial Measure."

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

You should read the following discussion of our historical performance, financial condition and future prospects in conjunction with our audited historical financial statements as of December 31, 2013 and for the period from inception (September 18, 2013) to December 31, 2013 and our unaudited historical financial statements as of and for the six months ended June 30, 2014 included elsewhere in this prospectus. The information provided below supplements, but does not form part of, these financial statements. This discussion contains forward-looking statements that are based on the views and beliefs of our management, as well as assumptions and estimates made by our management. Actual results could differ materially from such forward-looking statements as a result of various risk factors, including those that may not be in the control of management. For further information on items that could impact our future operating performance or financial condition, see the section entitled "Risk Factors" elsewhere in this prospectus.

Overview

Viper Energy Partners LP is a Delaware limited partnership formed by Diamondback to own, acquire and exploit oil and natural gas properties in North America. On September 19, 2013, Diamondback completed the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin for $440 million. Diamondback contributed these interests to us through the contribution of its wholly owned subsidiary, Viper Energy Partners LLC, in connection with the closing of the IPO.

As of June 30, 2014, our assets consisted of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. The mineral interests entitle us to receive an average 21.4% royalty interest on all production from this acreage with no additional future capital or operating expense required. As of June 30, 2014, there were 218 vertical wells and 30 horizontal wells producing on this acreage. The average net production on our acreage was approximately 1,919 net BOE/d during December 2013, and for the period from September 18, 2013 to December 31, 2013, royalty revenue generated from these mineral interests was $15.0 million. The average net production on our acreage was approximately 2,414 net BOE/d during June 2014, and royalty revenue generated from these mineral interests was $33.1 million for the six months ended June 30, 2014. Diamondback serves as the operator of approximately 55% of the acreage associated with these mineral interests.

Recent Developments

Initial Public Offering

Prior to the completion on June 23, 2014 of our IPO of 5,750,000 common units representing limited partner interests, Diamondback owned all of the general and limited partner interests in us. On June 23, 2014, we completed our IPO of 5,750,000 common units representing limited partner interests at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. We received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the IPO, Diamondback contributed all of the membership interests in Viper Energy Partners LP Predecessor to us in exchange for 70,450,000 common units. Furthermore, in exchange for the contribution of Viper Energy Partners LP Predecessor, we agreed to distribute to Diamondback all cash and the royalty income receivable on hand at the time of the IPO and the net proceeds from the IPO. As of June 30, 2014, we had distributed $137.5 million to Diamondback and recognized a payable balance of approximately $11.3 million to Diamondback. The contribution of Viper Energy Partners LP Predecessor to us was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

Credit Agreement

On July 8, 2014, we entered into a secured revolving credit agreement with Wells Fargo as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million. As of September 2, 2014, the borrowing base was $110.0 million. We had outstanding borrowings of $78.0 million as of September 11, 2014. Please see "—Liquidity and Capital Resources—Our Credit Agreement" for more information.

Acquisitions

Since our IPO, we have acquired, or have entered into definitive agreements to acquire, mineral interests in an aggregate of 3,261 net acres in the Midland and Delaware basins, 179 net royalty acres in the Eagle Ford basin and a minority equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests for aggregate consideration of approximately $105.0 million in cash. During August 2014, these acquired and to be acquired interests generated estimated royalty payments and distributions of approximately $7.9 million on an annualized basis. Based on our understanding of the near term development plans for the properties underlying certain of these interests and expected production, we currently anticipate that the aggregate royalty payments and distributions from these interests will be approximately $11.7 million for calendar year 2015. While we believe that the pricing and other 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 all of these pending acquisitions are not completed and/or our assumptions are not realized, the actual royalty payments and distributions received from these interests could be substantially less than the amounts we currently estimate.

Operating Results Overview

During the six months ended June 30, 2014, the average daily production on our properties was approximately 2,300 BOE/d, consisting of 1,766 Bbls/d of oil, 1,321 Mcf/d of natural gas and 314 Bbls/d of natural gas liquids. During the period from inception (September 18, 2013) through December 31, 2013, the average daily production on our properties was approximately 1,798 BOE/d, consisting of 1,436 Bbls/d of oil, 1,031 Mcf/d of natural gas and 190 Bbls/d of natural gas liquids.

Reserves and Pricing

Ryder Scott prepared estimates of our proved reserves at December 31, 2013. The prices used to estimate proved reserves for all periods did not give effect to derivative transactions, were held constant throughout the life of the properties and have been adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

	As of December 31, 2013
Estimated Net Proved Reserves:	
Oil (Bbls)	7,218,080
Natural gas (Mcf)	11,261,585
Natural gas liquids (Bbls)	1,175,123
Total (BOE)	10,270,135

	As of December 31, 2013	
	Unweighted Arithmetic Average First-Day-of-the-Month Prices	
Oil (Bbls)	$	92.64
Natural gas (Mcf)	$	5.03
Natural gas liquids (Bbls)	$	38.45

Sources of Our Revenue

Our revenues are derived from royalty payments we receive from our operators based on the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from natural gas during processing. For the six months ended June 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquid sales and 3% from natural gas sales. For the period from inception (September 18, 2013) through December 31, 2013, our revenues were derived 93% from oil sales, 5% from natural gas liquid sales and 2% from natural gas sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2013, West Texas Intermediate posted 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 December 31, 2013, the West Texas Intermediate posted price for crude oil was $98.17 per Bbl and the Henry Hub spot market price of natural gas was $4.31 per MMBtu. On June 30, 2014, the West Texas Intermediate posted price for crude oil was $106.07 per Bbl and the Henry Hub spot market price of natural gas was $4.39 per MMBtu.

Principal Components of Our Cost Structure

Production and Ad Valorem Taxes

Production taxes are paid on produced oil and natural gas based on a percentage of revenues from products sold at fixed rates established by federal, state or local taxing authorities. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and gas properties.

General and Administrative

In connection with the closing of the IPO, our general partner and Diamondback entered into the first amended and restated agreement of limited partnership, dated June 23, 2014. Our partnership agreement requires us to reimburse the general partner for all direct and indirect expenses incurred or paid 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 and its affiliates 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 by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us.

In connection with the closing of the IPO, we and our general partner entered into an advisory services agreement with Wexford pursuant to which Wexford will provide general financial and strategic advisory services to us and our general partner in exchange for a $500,000 annual fee and certain expense reimbursement.

We incurred costs for overhead, including the cost of management, operating and administrative services provided under the shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback, audit and other fees for professional services and legal compliance. In connection with the closing of the IPO, the shared services agreement with Diamondback E&P LLC was terminated. Please read “Certain Relationships and Related Party Transactions—Agreements and Transactions with Affiliates.”

Depreciation, Depletion and Amortization

Under the full cost accounting method, we capitalize costs within a cost center and then systematically expense those costs on a units of production basis based on proved oil and natural gas reserve quantities. We calculate depletion on all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization.

Income Tax Expense

The partnership is organized as a pass-through entity for income tax purposes. As a result, our partners are responsible for federal income taxes on their share of our taxable income.

We are subject to the Texas margin tax. Any amounts related to operations for 2013 or for the period in 2014 prior to the closing of the IPO on June 23, 2014 will be included in Diamondback's unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for the six months ended June 30, 2014 or the period from inception (September 18, 2013) through December 31, 2013, so no amount has been provided in the accompanying financial statements of Viper Energy Partners LP Predecessor.

Factors Affecting the Comparability of Our Historical Results to our Future Financial Results

Viper Energy Partners LP was formed on February 27, 2014 and did not own any assets prior to the contribution of Viper Energy Partners LP Predecessor to us on June 17, 2014. The assets of Viper Energy Partners LP Predecessor consisted of mineral interests in oil and natural gas properties in the Permian Basin, which were acquired by it on September 19, 2013. See Note 3 of our unaudited historical financial statements included elsewhere in this prospectus. The contribution of Viper Energy Partners LP Predecessor to us on June 17, 2014 was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. Therefore, the financial and operating data below represent the combination of Viper Energy Partners LP Predecessor and our operations for all periods.

Our future results of operations may not be comparable to our historical results of operations for the periods presented, primarily for the reasons described below:

Long-Term Debt

- In connection with the closing of the IPO, the subordinated note was converted to equity; therefore, we no longer have the note payable and related interest expense.
- On July 8, 2014, we entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be redetermined semi-annually with effective dates of April 1st and October 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. Under the credit agreement, the commitment of the lenders is equal to the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base. As of September 2, 2014, the borrowing base and the commitment were $110.0 million with Wells Fargo as the sole lender under the credit agreement. We had outstanding borrowings of $78.0 million as of September 11, 2014.

General and Administrative

- We anticipate incurring incremental general and administrative expenses of approximately $2.5 million annually as a result of being a publicly traded partnership, consisting of 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, NASDAQ Global Select Market listing, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees, director and officer insurance and director compensation.
- Our partnership agreement requires us to reimburse the general partner for all direct and indirect expenses incurred or paid 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 and its affiliates 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 by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us.
- On June 17, 2014, under the Long Term Incentive Plan ("LTIP") adopted in connection with the IPO, we granted awards of an aggregate of 2,500,000 unit options under the LTIP to executive officers of the general partner.
- In connection with the closing of the IPO, we and our general partner entered into an advisory services agreement with Wexford pursuant to which Wexford will provide general financial and strategic advisory services to us and our general partner in exchange for a $500,000 annual fee and certain expense reimbursement. Please read "Certain Relationships and Related Party Transactions—Agreements and Transactions with Affiliates."
- In connection with the closing of the IPO, we entered into a tax sharing agreement with Diamondback pursuant to which we will reimburse Diamondback for our share of state and local income and other taxes for which our results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax the partnership would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which we may be a member for this purpose, to owe less or no tax. In such a situation, we would reimburse Diamondback for the tax we would have owed had the tax attributes not been available or used for our benefit, even though Diamondback had no cash tax expense for that period. Please read "Certain Relationships and Related Party Transactions—Agreements and Transactions with Affiliates."

Results of Operations

The following table summarizes our revenue and expenses and production data for the periods indicated.

	Six Months Ended June 30, 2014 (unaudited)	Period From Inception (September 18, 2013) Through December 31, 2013
	(in thousands)	
Operating Results:		
Royalty income	$ 33,102	$ 14,987
Expenditures:		
Production and ad valorem taxes	2,313	972
Depletion	11,631	5,199
General and administrative expenses	285	—
General and administrative expenses—related party	156	87
Interest expense—related party, net of capitalized interest	10,755	5,741
Total expenditures	25,140	11,999
Net income	$ 7,962	$ 2,988
Allocation of net income:		
Net income attributable to the period through June 22, 2014	$ 7,021	
Net income attributable to the period June 23, 2014 through June 30, 2014	941	
	$ 7,962	
Production Data:		
Oil (Bbls)	319,704	150,815
Natural gas (Mcf)	239,032	108,264
Natural gas liquids (Bbls)	56,803	19,971
Combined volumes (BOE)	416,346	188,830
Daily combined volumes (BOE/d)	2,300	1,798

Royalty Income

Our royalty income for the six months ended June 30, 2014 was $33,102,000. For the period from inception (September 18, 2013) to December 31, 2013 our royalty income was $14,987,000.

Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes. Our operators received an average of $94.52 per Bbl of oil, $31.51 per Bbl of natural gas liquids and $4.58 per Mcf of natural gas for the volumes sold for the six months ended June 30, 2014. Our operators received an average of $92.07 per Bbl of oil, $35.32 per Bbl of natural gas liquids and $3.67 per Mcf of natural gas for the volumes sold for the period from inception (September 18, 2013) to December 31, 2013.

General and Administrative Expense

For the six months ended June 30, 2014, we incurred general and administrative expenses of $441,000. For the period from inception (September 18, 2013) to December 31, 2013, we incurred general and administrative expenses of $87,000.

Net Interest Expense

Net interest expense for the six months ended June 30, 2014 was $10,755,000. For the period from inception (September 18, 2013) through December 31, 2013 net interest expense was $5,741,000.

Liquidity and Capital Resources

Overview

We expect our primary sources of liquidity will be cash flows from operations and equity and debt financings and our primary uses of cash will be for paying distributions to our unitholders and for replacement and growth capital expenditures, including the acquisition, development and exploration of oil and natural gas properties. Subsequent to June 30, 2014, we entered into a revolving credit facility to be used for general partnership purposes.

Our partnership agreement does not require us to distribute any of the cash we generate from operations. We believe, however, that it will be in the best interests of our unitholders if we distribute a substantial portion of the cash we generate from operations. The board of directors of our general partner has adopted a policy to distribute an amount equal to the available cash we generate each quarter to our unitholders. Our first distribution, however, will include available cash for the period from June 23, 2014, the date of the closing of the IPO, through September 30, 2014. Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of the general partner following the end of such quarter. Available cash for each quarter will generally equal Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors of our general partner deems necessary or appropriate, if any.

Our Credit Agreement

On July 8, 2014, we entered into a $500.0 million senior secured revolving credit agreement with Wells Fargo as the administrative agent, sole book runner and lead arranger. The credit agreement matures on July 8, 2019. Under the credit agreement, the commitment of the lenders is equal to the lesser of the aggregate maximum credit amounts of the lenders and the borrowing base. As of September 2, 2014, the borrowing base and the aggregate commitment were $110.0 million, with Wells Fargo as the sole lender under the credit agreement. We had outstanding borrowings of $78.0 million as of September 11, 2014.

The outstanding borrowings under the credit agreement bear interest at a floating rate elected by us equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount 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 of July 8, 2019. The loan is secured by substantially all of our and our subsidiaries' assets.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

EBITDAX will be annualized beginning with the quarter ending September 30, 2014 and ending with the quarter ended March 31, 2015

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

Cash Flows

The following table presents our cash flows for the period indicated.

	Six Months Ended June 30, 2014 (unaudited)	Period From Inception (September 18, 2013) Through December 31, 2013
	(in thousands)	
Cash Flow Data:		
Cash flows provided by operating activities	$ 14,064	$ 4,845
Cash flows used in investing activities	(5,275)	(4,083)
Cash flows used in financing activities	(2,522)	—
Net increase in cash	$ 6,267	$ 762

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for oil and natural gas. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict.

Investing Activities

The purchase of oil and natural gas properties accounted for our cash outlays for investing activities. We used cash for investing activities of $5.3 million and $4.1 million during the six months ended June 30, 2014 and the period from inception (September 18, 2013) to December 31, 2013, respectively.

Financing Activities

We used cash for financing activities of $2.5 million during the six months ended June 30, 2014 primarily for interest payments on the subordinated note. In connection with the closing of the IPO, we agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand and the net proceeds from the IPO. As of June 30, 2014, we had distributed $137.5 million to Diamondback. We did not use any cash for financing activities during the period from inception (September 18, 2013) to December 31, 2013.

Contractual Obligations

We did not have any material contractual obligations and other commitments as of June 30, 2014.

Internal Controls and Procedures

We are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes-Oxley Act of 2002, and are therefore not required to make a formal assessment of the effectiveness of our internal controls over financial reporting for that purpose. Since becoming a public company, we are required to comply with the SEC's rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal controls over financial reporting. We will not be required to make our first assessment of our internal controls over financial reporting until the year following our first annual report required to be filed with the SEC. To comply with the requirements of being a public company, we will need to implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance and legal staff.

Further, our independent registered public accounting firm is not yet required to formally attest to the effectiveness of our internal controls over financial reporting, and will not be required to do so for as long as we are an "emerging growth company" pursuant to the provisions of the JOBS Act or as long as we are a non-accelerated filer. See "Summary—Emerging Growth Company Status." Please also see "Risk Factors—Risks Inherent in an Investment in Us—For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements that apply to other public companies."

New and Revised Financial Accounting Standards

We qualify as an "emerging growth company" pursuant to the provisions of the JOBS Act, enacted on April 5, 2012. Section 102 of the JOBS Act provides that an "emerging growth company" can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. However, we are choosing to "opt out" of such 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 election to "opt-out" of the extended transition period is irrevocable.

Critical Accounting Policies

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of our financial statements. See the notes to our consolidated financial statements included elsewhere in this prospectus for additional information regarding these accounting policies.

Use of Estimates

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated by our management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

We evaluate these estimates on an ongoing basis, using historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties and unit-based compensation.

Method of Accounting for Oil and Natural Gas Properties

We account for oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change.

Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property on an annual basis for possible impairment. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Oil and Natural Gas Reserve Quantities and Standardized Measure of Future Net Revenue

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. The SEC has defined proved reserves as the estimated quantities of oil and gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil and gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Royalty Interest and Revenue Recognition

Royalty interests represent the right to receive revenues (oil and natural gas sales), less production and operating taxes and post-production costs. Revenue is recorded when title passes to the purchaser.

Holders of royalty interests have no rights or obligations to explore, develop or operate the property and do not incur any of the costs of exploration, development and operation of the property.

Impairment

The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization, impairment and deferred income taxes exceed the discounted future net revenues of proved oil and natural gas reserves, less any related income tax effects, the excess capitalized costs are charged to expense. In calculating future net revenues, prices are calculated as the average oil and gas prices during the preceding 12-month period prior to the end of the current reporting period, determined as the unweighted arithmetic average first-day-of-the-month prices for the prior 12-month period and costs used are those as of the end of the appropriate quarterly period.

Accounting for Unit-Based Compensation

Unit-based compensation grants are measured at their grant date fair value and related compensation cost is recognized over the vesting period of the grant. The LTIP and related accounting policies are defined and described more fully in Note 8 in our unaudited historical financial statements included elsewhere in this prospectus. The determination of the fair value of an award requires significant estimates and subjective judgments regarding, among other things, the appropriate option pricing model, the expected life of the award and forfeiture rate assumptions. Estimates of the fair value of unit options granted during the six months ended June 30, 2014, were completed using a Black-Scholes option valuation model, which requires us to make several assumptions.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on results of operations for the period from inception (September 18, 2013) through December 31, 2013 or the six months ended June 30, 2014.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

Quantitative and Qualitative Disclosure about Market Risk

Commodity Price Risk

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

Credit Risk

We are subject to risk resulting from the concentration of royalty interest revenues in producing oil and natural gas properties and receivables with several significant purchasers. For the six months ended June 30, 2014, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (70%); and Permian Transport & Trading (12%). For the period from inception (September 18, 2013) to December 31, 2013, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (59%); and Permian Transport & Trading (19%). We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate 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 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We entered into this revolving credit facility on July 8, 2014, and as of September 11, 2014 had outstanding borrowings of $78.0 million. Our weighted-average interest rate on borrowings under our credit facility on September 11, 2014 was 2.16%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $500,000 based on the $78.0 million outstanding in the aggregate under our revolving credit facility on September 11, 2014.

BUSINESS

Overview

We are a Delaware limited partnership formed by Diamondback to own, acquire and exploit oil and natural gas properties in North America. Our primary business objective is to provide an attractive return to unitholders by focusing on business results, maximizing distributions through organic growth and pursuing accretive growth opportunities through acquisitions of mineral interests from Diamondback and from third parties. Our initial assets consisted of mineral interests in oil and natural gas properties in the Permian Basin in West Texas, substantially all of which are leased to working interest owners who bear the costs of operation and development. Diamondback contributed these assets, which it acquired in September 2013 from a third party for cash, to us upon the closing of our IPO on June 23, 2014.

Like Diamondback, we are currently focused primarily on oil and natural gas properties in the Permian Basin, which is one of the oldest and most prolific producing basins in North America. The Permian Basin, which consists of approximately 85,000 square miles centered around Midland, Texas, has been a significant source of oil production since the 1920s. The Permian Basin is known to have a number of zones of oil and natural gas bearing rock throughout. However, because of the nature of the rock in many of the potentially productive zones, historically it was not economic to exploit these zones. As a result, exploration and development was limited until recently when higher oil prices and more advanced completion techniques, including hydraulic fracturing, changed the economics of drilling and development of these zones and greatly increased the oil and natural gas industry's interest in the Permian Basin. Oil production in the Permian Basin has grown from 850,000 barrels per day in 2008 to 1.3 million barrels per day in 2013. Based on public statements made by a number of publicly traded oil and natural gas companies, and the successful horizontal well results of the industry, we believe that drilling activity in the Permian Basin is likely to continue to grow at least for several more years.

Diamondback is a publicly traded independent oil and natural gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin. Diamondback owns and controls our general partner and, prior to the completion of this offering, owns approximately 92% of our outstanding common units. Diamondback's total net acreage position in the Permian Basin (including the acreage underlying our mineral interests with respect to which it is operator) was approximately 72,300 net acres at June 30, 2014, and it serves as the operator of approximately 99% of its leased acreage. As of December 31, 2013, Diamondback had estimated proved oil and natural gas reserves of 63,586 MBOE (including the estimated proved reserves associated with our mineral interests) based on a reserve report prepared by Ryder Scott. Of these reserves, approximately 45% were classified as PDP reserves and approximately 67% were oil, 17% were natural gas liquids and 16% were natural gas. PUD reserves included in this estimate are from 206 vertical gross (151 net) well locations on 40-acre spacing and 43 gross (31 net) horizontal well locations. We believe that the properties held by Diamondback include properties that have, or with additional development will have, production and reserves characteristics that could make them attractive for inclusion in our partnership. We believe Diamondback's significant ownership interest in us will motivate it to offer additional mineral and other interests in oil and natural gas properties to us in the future, although Diamondback has no obligation to do so. Please read "—Our Relationship with Diamondback."

Our Properties

Our initial assets consisted of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin, approximately 55% of which are operated by Diamondback. Diamondback acquired the mineral interests for $440 million on September 19, 2013. The mineral interests entitle us to receive an average 21.4% royalty interest on all production from this acreage with no additional future capital or operating expense required. As of June 30, 2014, there were 218 vertical wells and 30 horizontal wells producing on this acreage, and average net production was approximately 2,414 net BOE/d during June 2014. In addition, there were six vertical wells and 17 horizontal wells in various stages of completion. For the six months ended June 30, 2014 and the period from our inception (September 18, 2013) to December 31, 2013, royalty revenue generated from these mineral interests was $33.1 million and $15.0 million, respectively.

The estimated proved oil and natural gas reserves of our initial assets, as of December 31, 2013, were 10,270 MBOE based on a reserve report prepared by Ryder Scott, our independent reserve engineer. Of these reserves, approximately 48% were classified as PDP reserves. PUD reserves included in this estimate were from 106 vertical gross well locations on 40-acre spacing and 24 gross horizontal well locations. As of December 31, 2013, our proved reserves were approximately 70% oil, 11% natural gas liquids and 18% natural gas.

Our mineral interests entitle us to receive an average of 21.4% royalty interest on an acreage weighted basis from our approximately 14,804 gross (12,687 net) acres. The actual royalty percentage varies by lease and ranges from 7.8% to 25%. The average royalty percentage on a production basis can therefore vary over time depending on the relative amount of production from the various leases. On an acreage weighted basis, our average royalty percentage is 20.6% on the portion of the acreage that Diamondback operates and is 22.3% on the portion of the acreage operated by others. From September 18, 2013 through June 30, 2014, the average royalty percentage was 19.4% owing to some of the lower royalty percentage acreage being more developed at this time. As additional acreage is developed, we anticipate that the average royalty percentage on a production basis will change and likely will increase as more of the higher royalty acreage is developed.

Based on Diamondback's evaluation of applicable geologic and engineering data as of June 30, 2014, with respect to the approximate 55% of our mineral interests for which it is the operator, Diamondback had 68 identified potential vertical drilling locations on 40-acre spacing and an additional 184 identified potential vertical drilling locations based on 20-acre downspacing. As of such date, Diamondback had also identified 313 potential horizontal drilling locations in multiple horizons on our acreage. We do not have potential (not involving proved reserves) drilling location information with respect to the portion of our properties not operated by Diamondback, although we believe that such portion has very similar production characteristics to the portion operated by Diamondback. The operator of a majority of our properties not operated by Diamondback is RSP Permian. Diamondback has advised us that it believes it has a good relationship with RSP Permian and that it shares, on occasion, drilling and production information with RSP Permian in order to encourage further development of our properties. Additionally, Diamondback has participated with RSP Permian in the drilling and completion of five horizontal wells on shared acreage subject to our mineral interests.

The gross EURs from the future PUD vertical wells included in our reserve report on 40-acre spacing, as estimated by Ryder Scott as of December 31, 2013, range from 104 MBOE per well, consisting of 80 MBbls of oil and 148 MMcf of natural gas, to 146 MBOE per well, consisting of 112 MBbls of oil and 208 MMcf of natural gas, with an average EUR per well of 134 MBOE, consisting of 102 MBbls of oil and 193 MMcf of natural gas. Diamondback has advised us that it currently anticipates a reduction of approximately 20% in EURs from vertical wells drilled on 20-acre spacing.

With respect to 30 horizontal wells drilled by our operators on our acreage for the period from June 2012 through June 2014, the average 30-day initial production ("IP") rate was 679 BOE/d and the average 24-hour IP rate was 960 BOE/d from lateral lengths averaging 5,962 feet.

Our Relationship with Diamondback

Diamondback owns and controls our general partner and, prior to the completion of this offering, owns approximately 92% of our outstanding common units. We believe that the properties held by Diamondback include properties that have, or with additional development will have, production and reserves characteristics that could make them attractive for inclusion in our partnership. We believe Diamondback's significant ownership in us will motivate it to offer additional mineral and other interests in oil and natural gas properties to us in the future, although Diamondback has no obligation to do so and may elect to dispose of mineral and other interests in such properties without offering us the opportunities to acquire them.

We believe Diamondback views our partnership as part of its growth strategy, and we believe that Diamondback will be incentivized to pursue acquisitions jointly with us in the future. However, Diamondback will regularly evaluate acquisitions and may elect to acquire properties without offering us the opportunity to participate in such transactions. Moreover, Diamondback may not be successful in identifying potential acquisitions. Diamondback is free to act in a manner that is beneficial to its interests without regard to ours, which may include electing not to present us with acquisition or disposition opportunities. Please read “Conflicts of Interest and Fiduciary Duties.”

In addition, neither we nor our subsidiaries nor our general partner has any employees. Diamondback provides management, operating and administrative services to us and our general partner. Please read “Management” and “Certain Relationships and Related Party Transactions.”

Prior to October 11, 2012, Wexford beneficially owned 100% of the equity interests in Diamondback. Upon completion of Diamondback’s initial public offering, Wexford beneficially owned approximately 44.4% of its common stock. As a result of the issuance of additional shares of common stock by Diamondback and sales of its common stock by affiliates of Wexford, as of August 31, 2014, Wexford beneficially owned approximately 14.4% of the common stock of Diamondback.

Business Strategies

Our primary business objective is to provide an attractive return to unitholders by focusing on business results, maximizing distributions through organic growth and pursuing accretive growth opportunities through acquisitions of mineral interests from Diamondback and from third parties. We intend to accomplish this objective by executing the following strategies:

- ***Capitalize on the development of the properties underlying our mineral interests to grow our distributions.*** Our initial assets consisted of mineral interests in the Permian Basin in West Texas. We expect the production from our mineral interest will increase as Diamondback and our other operators continue to actively drill and develop our acreage. We expect to capitalize on this development, cost-free to us, and believe the resulting increase in our aggregate royalty payments will enable us to grow our distributions.
- ***Leverage our relationship with Diamondback to participate with it in acquisitions of mineral or other interests in producing properties from third parties and to increase the size and scope of our potential third-party acquisition targets.*** We intend to make opportunistic acquisitions of mineral interests that have substantial oil-weighted resource potential and organic growth potential. Diamondback was formed in part to acquire and develop oil and natural gas properties, some of which will likely meet our acquisition criteria. In addition, Diamondback’s executives have long histories of evaluating, pursuing and consummating oil and natural gas property acquisitions in North America. Through our relationships with Diamondback and its affiliates, we have access to their significant pool of management talent and industry relationships, which we believe provide us with a competitive advantage in pursuing potential third-party acquisition opportunities. We may have additional opportunities to work jointly with Diamondback to pursue certain acquisitions of mineral or other interests in oil and natural gas properties from third parties. For example, we and Diamondback may jointly pursue an acquisition where we would acquire mineral or other interests in properties and Diamondback would acquire the remaining working and revenue interests in such properties. We believe this arrangement may give us access to third-party acquisition opportunities that we would not otherwise be in a position to pursue.
- ***Seek to acquire from Diamondback, from time to time, mineral or other interests in producing oil and natural gas properties that meet our acquisition criteria.*** We may have additional opportunities to acquire mineral or other interests in producing oil and natural gas properties directly from Diamondback or third parties from time to time in the future. We believe Diamondback may be incentivized to sell properties to us, as doing so may enhance Diamondback’s economic returns by monetizing long-lived

producing properties while potentially retaining a portion of the resulting cash flow through distributions on Diamondback's limited partner interests in us. However, none of Diamondback or any of its affiliates is contractually obligated to offer or sell interests in any properties to us.

Competitive Strengths

We believe that the following competitive strengths will allow us to successfully execute our business strategies and achieve our objective of growing our business and maximizing total distributions to our unitholders:

- ***Oil rich resource base in one of North America's leading resource plays.*** All of the acreage underlying our mineral interests is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. The majority of our current properties are well positioned in the core of the Wolfberry play. Production on our properties for the six months ended June, 2014 was approximately 77% oil, 14% natural gas liquids and 9% natural gas. As of December 31, 2013, our estimated net proved reserves were comprised of approximately 70% oil and 11% natural gas liquids, which allows us to benefit from the currently more favorable pricing of oil and natural gas liquids as compared to natural gas. We believe that we will have a strong, growing production profile driven by Diamondback, a growth-oriented operator.
- ***Multi-year drilling inventory in one of North America's leading oil resource plays.*** We expect our reserves and cash available for distributions to grow organically as our operators continue to drill new wells on our acreage. Diamondback, as the operator of approximately 55% of our properties, has advised us that it has identified a multi-year inventory of potential drilling locations for our oil-weighted reserves from the acreage underlying our mineral interests. As of June 30, 2014, with respect to the approximate 55% of our properties operated by it, Diamondback had 68 identified potential vertical drilling locations based on 40-acre spacing and an additional 184 identified potential vertical drilling locations based on 20-acre downspacing. Diamondback also believes that there are a significant number of horizontal locations that could be drilled on the acreage. Based on Diamondback's initial results and those of other operators in the area to date, combined with its interpretation of various geologic and engineering data, Diamondback has identified 313 potential horizontal locations on the acreage operated by Diamondback. These locations exist across most of the acreage and in multiple horizons. Of these 313 potential locations, 121 are in the Wolfcamp B or Lower Spraberry horizons, with the remaining locations in the Wolfcamp A, Clearfork, Middle Spraberry or Cline (or Wolfcamp D) horizons. Diamondback's current potential horizontal location count is based on 660-foot spacing between wells in the Wolfcamp B and Lower Spraberry horizons in Midland County, 880-foot spacing in the Middle Spraberry horizon and 1,320-foot spacing in other horizons. The ultimate inter-well spacing may be less than these amounts, which would result in a higher location count. Based on horizontal wells drilled to date, Ryder Scott assigned reserves to PUD locations ranging from 374 MBOE for 5,000-foot laterals in the Middle Spraberry to 847 MBOE for 10,000-foot laterals in the Wolfcamp B. When normalized to 7,500-foot laterals, Ryder Scott assigned PUD values of 638 MBOE for the Wolfcamp B horizon, 643 MBOE for the Lower Spraberry horizon and 562 MBOE for the Middle Spraberry horizon. These PUD locations, as assigned by Ryder Scott, are for direct offsets to producing wells. Based on various geologic and engineering parameters, we believe that the estimates assigned to these PUD locations are reasonable estimates for PUD locations on the remaining portion of our acreage. Additionally, we believe that there is similar potential for horizontal development on the portion of our acreage for which Diamondback is not the operator.
- ***Experienced and proven management team.*** The members of our executive team have an average of over 25 years of industry experience, most of which were focused on resource play development in the Permian Basin. This team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with property acquisitions. We expect to benefit from the industry relationships fostered by

the team's decades of experience in the Permian Basin. Prior to joining Diamondback, the Chief Executive Officer of our general partner held management positions at Apache Corporation, Laredo Petroleum Holdings, Inc. and Burlington Resources. The Chief Financial Officer of our general partner previously served as the Controller/Tax Director at Hiland Partners, a publicly traded master limited partnership, and has over eight years of accounting experience at other public companies. We believe the experience of our management team is essential for us to grow from our initial property base.

- ***Favorable and stable operating environment.*** We will focus our growth in the Permian Basin, one of the oldest hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. With approximately 380,000 wells drilled in the Permian Basin since the 1940s, we believe that the geological and regulatory environment is more stable and predictable, and that we are faced with fewer operational risks, in the Permian Basin as compared to emerging hydrocarbon basins. We believe that the impact of the proven application of new technology, combined with the substantial geological information available about the Permian Basin, also reduces the risk of development and exploration activities as compared to emerging hydrocarbon basins.
- ***Financial flexibility to fund expansion.*** We have a conservative balance sheet. We will seek to maintain financial flexibility to allow us to opportunistically purchase accretive mineral and other interests. We have entered into a revolving credit facility to be used for general partnership purposes. We believe that we have a unique distribution profile with initial distributions almost exclusively supported by mineral interests. We also expect to produce peer-leading margins unburdened by lease operating expenses.

Oil and Natural Gas Data

Proved Reserves

SEC Rule-Making Activity

In December 2008, the SEC released its final rule for "Modernization of Oil and Gas Reporting." These rules require disclosure of oil and gas proved reserves by significant geographic area, using the arithmetic 12-month average beginning-of-the-month price for the year, as opposed to year-end prices as had previously been required, unless contractual arrangements designate the price to be used. Other significant amendments included the following:

- Disclosure of unproved reserves: probable and possible reserves may be disclosed separately on a voluntary basis.
- Proved undeveloped reserve guidelines: reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered and they are scheduled to be drilled within the next five years, unless the specific circumstances justify a longer time.
- Reserves estimation using new technologies: reserves may be estimated through the use of reliable technology in addition to flow tests and production history.
- Reserves personnel and estimation process: additional disclosure is required regarding the qualifications of the chief technical person who oversees the reserves estimation process. We are also required to provide a general discussion of our internal controls used to assure the objectivity of the reserves estimate.
- Non-traditional resources: the definition of oil and gas producing activities has expanded and focuses on the marketable product rather than the method of extraction.

We have adopted the rules upon inception.

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2013 were prepared by Ryder Scott. A reserve audit is not the same as a financial audit and is less vigorous in nature than an independent reserve report where the independent reserve engineer determines the reserves on its own.

Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis.

Under SEC rules, 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—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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves as of December 31, 2013 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. The proved reserves for our properties were estimated by performance methods, analogy or a combination of both methods. Approximately 90% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 10% of the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Our petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members met with our independent reserve engineers periodically during the period covered by the reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Our Vice President—Reservoir Engineering is primarily responsible for overseeing the preparation of all of our reserve estimates. Our Vice President—Reservoir Engineering is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 26 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by our operators;
- preparation of reserve estimates by our Vice President—Reservoir Engineering or under his direct supervision;
- review by our Vice President—Reservoir Engineering of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our Vice President—Reservoir Engineering to our Chief Executive Officer;
- verification of property ownership by our land department; and
- no employee's compensation is tied to the amount of reserves booked.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2013 based on the reserve report prepared by Ryder Scott. The reserve report has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve report are located in the continental United States.

	As of December 31, 2013
Estimated proved developed reserves:	
Oil (Bbls)	3,692,207
Natural gas (Mcf)	6,280,409
Natural gas liquids (Bbls)	609,303
Total (BOE)	5,348,245
Estimated proved undeveloped reserves:	
Oil (Bbls)	3,525,873
Natural gas (Mcf)	4,981,176
Natural gas liquids (Bbls)	565,820
Total (BOE)	4,921,889
Estimated Net Proved Reserves:	
Oil (Bbls)	7,218,080
Natural gas (Mcf)	11,261,585
Natural gas liquids (Bbls)	1,175,123
Total (BOE)(1)	10,270,135
Percent proved developed	52.1%

(1) 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 revised SEC guidelines applicable to reserve estimates as of the end of such periods. The unweighted arithmetic average first day of the month prices were $92.64 per Bbl for oil, $38.45 per Bbl for NGLs and $5.03 per Mcf for natural gas at

December 31, 2013. 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.

As of December 31, 2013, our proved developed reserves totaled 3,692 MBbls of oil, 6,280 MMcf of natural gas and 609 MBbls of natural gas liquids, for a total of 5,348 MBOE. Of the total proved developed reserves, 93% were producing and the remaining 7% were from wells that had been stimulated but were not yet producing hydrocarbons. Producing reserves were from 200 vertical wells and 16 horizontal wells, of which Diamondback was the operator of 102 vertical wells and 11 horizontal wells and RSP Permian was the operator of 74 vertical wells and five horizontal wells. The remaining 24 vertical wells were operated by various other companies. Of the total 216 producing wells, Diamondback had a working interest in 133 wells. Non-producing reserves were from three vertical wells and two horizontal wells in various stages of completion and one well that was behind pipe recompletion.

The foregoing reserves are all located within the continental United States. Reserve engineering is 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. See "Risk Factors." We have not filed any estimates of total, proved net oil or natural gas reserves with any federal authority or agency other than the SEC.

Additional information regarding our proved reserves can be found in the reserve report as of December 31, 2013, which is filed as Exhibit 99.1 to the registration statement of which this prospectus is a part.

Proved Undeveloped Reserves

As of December 31, 2013, our proved undeveloped reserves totaled 3,526 MBbls of oil, 4,981 MMcf of natural gas and 566 MBbls of natural gas liquids, for a total of 4,922 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Our undeveloped reserves were from 106 vertical wells and 24 horizontal wells, of which Diamondback was the operator of 69 vertical wells and 15 horizontal wells and RSP Permian was the operator of the remaining 37 vertical wells and nine horizontal wells. Diamondback also had a non-operated working interest in seven of the vertical wells and all of the nine horizontal wells that were operated by RSP Permian. 20 of the horizontal locations were Wolfcamp B wells, two were Lower Spraberry wells and two were Middle Spraberry wells.

All of our PUD drilling locations are scheduled to be drilled prior to the end of 2018. As of December 31, 2013, approximately 3.6% of our total proved reserves were classified as proved developed non-producing.

Changes in PUDs that occurred since the date of our acquisition of reserves through December 31, 2013 were primarily due to:

- additions of 1,743 MBOE, primarily from 20 horizontal well locations, 16 in the Wolfcamp interval and four in Spraberry intervals, attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;
- the conversion of approximately 589 MBOE attributable to PUDs into proved developed reserves; and
- negative revisions of approximately 238 MBOE in PUDs primarily due to lowered natural gas and natural gas liquids forecasts associated with recent gas flaring.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following table sets forth information regarding the operators' net production of oil, natural gas and natural gas liquids, all of which is from the Permian Basin in West Texas, and certain price and cost information for each of the periods indicated:

	Six Months Ended June 30, 2014	Period from Inception (September 18, 2013) to December 31, 2013
Production Data:		
Oil (Bbls)	319,704	150,815
Natural gas (Mcf)	239,032	108,264
Natural gas liquids (Bbl)	56,803	19,971
Combined volumes (BOE)	416,346	188,830
Daily combined volumes (BOE/d)	2,300	1,798
Average Prices:		
Oil (per Bbl)	$ 94.52	$ 92.07
Natural gas (per Mcf)	4.58	3.67
Natural gas liquids (per Bbl)	31.51	35.32
Combined (per BOE)	79.51	79.37

Productive Wells

As of June 30, 2014, our operators owned a working interest in 248 productive wells located on the acreage in which we have a mineral interest. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

Acreage

The following table sets forth information as of June 30, 2014 relating to our gross acreage:

Basin	Developed Acreage(1)	Undeveloped Acreage(2)	Total Acreage
Permian	8,720	6,084	14,804

(1) Developed acres are acres spaced or assigned to productive wells and do not include undrilled acreage held by production under the terms of the lease. The value provided is for vertical wells only and are based on 40 acres per well for wells drilled as of June 30, 2014.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Drilling Results

The following table sets forth information with respect to the number of wells completed by our operators during the periods indicated. Each of these wells was drilled in Midland County in the Permian Basin of West Texas. 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 or the economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Six Months Ended June 30, 2014
Development:	
Productive	16
Dry	—
Exploratory:	
Productive	9
Dry	—
Total	
Productive	25
Dry	—

As of June 30, 2014, our operators had 23 wells in the process of drilling, completing or dewatering or shut in awaiting infrastructure that are not reflected in the above table.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. 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. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional 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. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. Further, oil and natural gas 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

Generally, demand for oil and natural gas decreases during the summer months and increases during the winter months. 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 and lease stipulations can limit drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for our operators in meeting well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations.

Regulation

The following disclosure describes regulation more directly associated with operators of oil and natural gas properties, including our current operators, and other owners of working interests in oil and natural gas properties. To the extent we elect in the future to engage in the exploration, development and production of oil and natural gas properties, we would be directly subject to the same regulations described below. For purposes of this section, where applicable, references to "we," "us," and "our" refer to Viper Energy Partners LP to the extent the partnership were to acquire working interests in the future as well as to any operators of our properties, including our current operators.

Oil and natural gas operations are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases the cost of doing business.

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. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency ("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 and joint and several liability nature of such laws and regulations could impose liability upon us 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, such wastes may constitute "solid wastes" that are subject to the less stringent requirements of non-hazardous waste provisions. However, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase the costs to manage and dispose of wastes.

Remediation of Hazardous Substances

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the "Superfund" law, and analogous state laws, generally imposes strict and 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, 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. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such "hazardous substances" have been released.

Water Discharges

The Federal Water Pollution Control Act of 1972, as amended, also known as the "Clean Water Act," the Safe Drinking Water Act ("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. 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. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. 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. In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from shale formations. The EPA stated that it will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for shale gas in 2014. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The Oil Pollution Act 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 to 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, as amended, 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, on August 16, 2012, the EPA published final regulations under the federal Clean Air Act that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail below in "—Regulation of Hydraulic Fracturing." These laws and regulations may increase the costs of compliance for some facilities we own or operate, 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. 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 such 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 under existing provisions of the federal Clean Air Act, including rules which regulate emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. 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 natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010.

The EPA has continued to adopt GHG regulations of other industries, such as the September 2013 proposed GHG rule that, if finalized, would set new source performance standards for new coal-fired and natural-gas fired power plants, which could have an adverse effect on our financial condition and results of operations. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility. In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of greenhouse gases and almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas 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, and state and local climate change initiatives and, 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 our production and increase our costs and 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 operations.

Regulation of 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. The federal 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, specifically as "Class II" UIC wells. In addition, on May 9, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the 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 announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

Legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress.

On August 16, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, or VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule seeks to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely responsive to some of these requests. For example, on September 23, 2013, the EPA published an amendment extending compliance dates for certain storage vessels. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013 that would update existing regulation for hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water.

In addition, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. These ongoing or proposed studies, depending on their degree of pursuit and whether any meaningful results are obtained, 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 coordinating 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 and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted new legislation requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission has adopted rules and regulations implementing this legislation that apply to all wells for which the Railroad Commission issues an initial drilling permit after February 1, 2012. The new law requires that the well operator disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act ("OSHA") for disclosure 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.

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 that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities 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. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. 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.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases the cost of doing business, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission ("FERC"). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production

The operations of our operators are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities, including seasonal wildlife closures;
- the rates of production or “allowables”;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas that our operators can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. The U.S. Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the U.S. Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price and marketing of natural gas. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 (“NGA”) and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in “first sales.” Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which our operators may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that our operators produce, as well as the revenues our operators receive for sales of natural gas and release of natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our operators' costs of transporting gas to point-of-sale locations.

Oil Sales and Transportation

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to our operators to the same extent as to our or their competitors.

State Regulation

Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on the market value of oil production and a 7.5% severance tax on the market value of natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations our operators can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Employees

We are managed and operated by the board of directors and executive officers of our general partner. However, neither we, our subsidiary nor our general partner have any employees. All of the employees that will conduct our business, including our executive officers, are employed by Diamondback. We and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford will provide general financial and strategic advisory services to us and our general partner.

As of June 30, 2014, Diamondback had 85 full-time employees. None of Diamondback's employees are represented by labor unions or covered by any collective bargaining agreements. Diamondback also hires independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist its full time employees. Please read "Management" and "Certain Relationships and Related Party Transactions."

Facilities

Diamondback leases office space for our principal executive offices in Midland, Texas. We believe that these facilities are adequate for our current operations.

Legal Proceedings

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

MANAGEMENT

Management of Viper Energy Partners LP

We are managed and operated by the board of directors and executive officers of our general partner, the latter of whom are employed by Diamondback.

Diamondback owns all the membership interests in our general partner. As a result of owning our general partner, Diamondback has the right to appoint all members of the board of directors of our general partner, including the independent directors. Our unitholders are not entitled to elect our general partner or its directors or otherwise directly participate in our management or operation. Our general partner owes certain duties to our unitholders as well as a fiduciary duty to its owner.

The board of directors of our general partner has six directors, two of whom are independent as defined under the independence standards established by NASDAQ and the Exchange Act. W. Wesley Perry and W. Duncan Kennedy serve as the initial independent members of the board of directors of our general partner. In accordance with the rules of NASDAQ, Diamondback will appoint one additional independent member within one year of the effective date of the registration statement relating to our IPO, bringing the total number of directors on the board of directors of our general partner to seven. NASDAQ 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. 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 NASDAQ and the Exchange Act, subject to the transitional relief during the one-year period following completion of the IPO.

The executive officers of our general partner manage the day-to-day affairs of our business. All of the executive officers of our general partner also serve as executive officers of Diamondback. Our executive officers listed below allocate their time between managing our business and the business of Diamondback. Our executive officers intend, however, to devote as much time as is necessary for the proper conduct of our business.

Our partnership agreement requires us to reimburse our general partner and its affiliates, including Diamondback, for all expenses they incur and payments they make on our behalf in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates 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 by its affiliates. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us. In addition, we and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford provides general finance and advisory services in exchange for a fee and certain expense reimbursement. Please read “Certain Relationships and Related Party Transactions—Agreements and Transactions with Affiliates.”

Executive Officers and Directors of Our General Partner

The following table shows information for the executive officers and directors of our general partner. Directors hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board. 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
Travis D. Stice	52	Chief Executive Officer, Director
Teresa L. Dick	44	Chief Financial Officer, Senior Vice President and Assistant Secretary
Russell Pantermuehl	54	Vice President—Reservoir Engineering
Randall J. Holder	61	Vice President, General Counsel and Secretary
Steven E. West	53	Executive Chairman, Director
W. Wesley Perry	58	Director
W. Duncan Kennedy	53	Director
Michael L. Hollis	39	Director
James L. Rubin	30	Director

Travis D. Stice. Mr. Stice has served as Chief Executive Officer and a director of our general partner since February 2014. He has served as Chief Executive Officer of Diamondback since January 2012 and as a director since November 2012. Prior to his current position with Diamondback, Mr. Stice served as its President and Chief Operating Officer from April 2011 to January 2012. Mr. Stice has also served on the board of managers of MidMar Gas LLC, or MidMar, an entity that owns a gas gathering system and processing plant, since 2011 and as Vice President and Secretary of MidMar since April 2012. From November 2010 to April 2011, Mr. Stice served as a Production Manager of Apache Corporation, an oil and gas exploration company. Mr. Stice served as a Vice President of Laredo Petroleum Holdings, Inc, an oil and gas exploration company, from September 2008 to September 2010 and as a Development Manager of ConocoPhillips/Burlington Resources Mid-Continent Business Unit, an oil and gas exploration company, from April 2006 until August 2008. Prior to that, Mr. Stice held a series of positions at Burlington Resources, an oil and gas exploration company, most recently as a General Manager, Engineering, Operations and Business Reporting of its Mid Continent Division from January 2001 until Burlington Resources' acquisition by ConocoPhillips in March 2006. Mr. Stice has over 26 years of experience in production operations, reservoir engineering, production engineering and unconventional oil and gas exploration and over 18 years of management experience. Mr. Stice graduated from Texas A&M University with a Bachelor of Science degree in Petroleum Engineering. He is a registered engineer in the State of Texas, and is a 25-year member of the Society of Petroleum Engineers.

We believe Mr. Stice's expertise and extensive industry and executive management experience, including at Diamondback, make him a valuable asset to the board of directors of our general partner.

Teresa L. Dick. Ms. Dick has served as Chief Financial Officer, Senior Vice President and Assistant Secretary of our general partner since February 2014. She has also served as Diamondback's Chief Financial Officer and Senior Vice President since November 2009 and as its Corporate Controller from November 2007 until November 2009. From June 2006 to November 2007, Ms. Dick held a key management position as the Controller/Tax Director at Hiland Partners, a publicly traded midstream energy master limited partnership. Ms. Dick has over 19 years of accounting experience, including over eight years of public company experience in both audit and tax areas. Ms. Dick received her Bachelor of Business Administration degree in Accounting from the University of Northern Colorado. She is a certified public accountant and a member of the American Institute of CPAs and the Council of Petroleum Accountants Societies.

Russell Pantermuehl. Mr. Pantermuehl has served as Vice President—Reservoir Engineering of our general partner since February 2014. He has also served as Diamondback's Vice President—Reservoir Engineering since

August 2011, and, prior to his current position at Diamondback, Mr. Pantermuehl served as a reservoir engineering supervisor for Concho Resources Inc., an oil and gas exploration company, from March 2010 to August 2011. Mr. Pantermuehl worked for ConocoPhillips Company as a reservoir engineering advisor from January 2005 to March 2010. Mr. Pantermuehl also worked as an independent consultant in the oil and gas industry from March 2000 to December 2004. He received a Bachelor of Science degree in Petroleum Engineering from Texas A&M University.

Randall J. Holder. Mr. Holder has served as Vice President, General Counsel and Secretary of our general partner since February 2014. Mr. Holder joined Diamondback in November 2011 as General Counsel and Vice President responsible for legal and human resources and currently also serves as Secretary. Prior to joining Diamondback, Mr. Holder served as General Counsel and Vice President for Great White Energy Services LLC, an oilfield services company, from November 2008 to November 2011. He served as Executive Vice President and General Counsel for R.L. Hudson and Company, a supplier of molded rubber and plastic components, from February 2007 to October 2008. He was in private practice of law and a member of Holder Betz LLC from February 2005 to February 2007. Mr. Holder served as Vice President and Assistant General Counsel for Dollar Thrifty Automotive Group, a vehicle rental company, from January 2003 to February 2005 and as Vice President and General Counsel for Thrifty Rent-A-Car System, Inc., a vehicle rental company, from September 1996 to December 2002. He also served as Vice President and General Counsel for Pentastar Transportation Group, Inc. from November 1992 to September 1996, which was wholly-owned by Chrysler Corporation. Mr. Holder started his legal career with Tenneco Oil Company where he served as a Division Attorney providing legal services to the company's mid-continent division for ten years. He received a Juris Doctorate degree from Oklahoma City University.

Steven E. West. Mr. West has served as a director and Executive Chairman of our general partner since February 2014. Mr. West has also served as a director of Diamondback since December 2011 and as its Chairman of the Board since October 2012. He served as Diamondback's Chief Executive Officer from January 1, 2009 to December 31, 2011. Since January 2011, Mr. West has been a partner at Wexford Capital LP, focusing on Wexford's private equity energy investments. From August 2006 until December 2010, Mr. West served as senior portfolio advisor at Wexford. From August 2003 until August 2006, he was the chief financial officer of Sunterra Corporation, a former Wexford portfolio company. From December 1993 until July 2003, Mr. West held senior financial positions at Coast Asset Management and IndyMac Bank. Prior to that, he worked at First Nationwide Bank, Lehman Brothers and Peat Marwick Mitchell & Co., the predecessor of KPMG LLP. Mr. West holds a Bachelor of Science degree in Accounting from California State University, Chico.

We believe that Mr. West's background in finance, accounting and private equity energy investments, as well as his executive management skills developed as part of his career with Wexford, its portfolio companies and other financial institutions qualify him to serve on the board of directors of our general partner.

W. Wesley Perry. Mr. Perry has been a member of the board of directors of our general partner since June 2014. He served as President of EGL Resources, Inc., an oil and gas operations company based in Texas and New Mexico, from January 1994 until July 2008, before becoming the Chief Executive Officer. He has also served as manager of PBEX, LLC since July 2012. Mr. Perry has served as a director of Genie Energy, Ltd. from September 2009 and is chairman of the audit committee. He also serves as Chairman of Genie Energy International Corporation. He served as a director of UTG, Inc. from July 2005 to June 2013. He served as a director of American Capital Insurance Company and Texas Imperial Life Insurance Company from 2006 to 2009 and as a director of Western National Bank from 2005 to 2009. Mr. Perry has owned and operated SES Investments, Ltd., an oil and gas investment company, since 1980. He served as the Mayor of Midland, Texas, from January 2008 through January 2014. He also served on the Midland City Council as an at-large councilperson from 2002 to 2008. Mr. Perry holds a Bachelor of Science degree in Engineering from the University of Oklahoma.

We believe that Mr. Perry's extensive experience in the oil and gas industry and his strong financial background qualify him to serve on the board of directors of our general partner.

W. Duncan Kennedy has been a member of the board of directors of our general partner since September 2014. He has served as President of THE NINETY-SIX CORPORATION since June 2002, and as Vice President of Kennedy Minerals, Ltd since 2005. Both companies are engaged in oil and gas exploration and mineral acquisition. Mr. Kennedy graduated from Southern Methodist University with a Bachelor of Arts degree in Geology.

We believe that Mr. Kennedy's extensive experience in the oil and gas industry qualifies him to serve on the board of directors of our general partner.

Michael L. Hollis. Mr. Hollis has been a member of the board of directors of our general partner since June 2014. He has served as Vice President—Drilling of Diamondback since September 2011. Prior to his current position with Diamondback, Mr. Hollis served in various roles, most recently as drilling manager at Chesapeake Energy Corporation, an oil and gas exploration company, from June 2006 to September 2011. He worked for ConocoPhillips Company as a senior drilling engineer from January 2002 to June 2006 and as a process engineer from 2001 to 2003. Mr. Hollis also worked as a production engineer for Burlington Resources from 1998 to 2001 as well as from June 2003 to January 2004. Mr. Hollis received his Bachelor of Science degree in Chemical Engineering from Louisiana State University.

We believe that Mr. Hollis' extensive experience in the oil and gas industry, including at Diamondback, qualifies him to serve on the board of directors of our general partner.

James L. Rubin. Mr. Rubin has been a member of the board of directors of our general partner since June 2014. He has served as a partner at Wexford since 2012 and currently serves as Portfolio Manager and Co-Head of Equities and as a member of Wexford's hedge fund investment committee. From 2006 to 2012, he served as an analyst and later as Vice President, focusing on Wexford's public and private energy investments**.** Mr. Rubin graduated cum laude from Yale University with a Bachelor of Arts degree with honors in political science and economics.

We believe that Mr. Rubin's strong financial background qualifies him to serve on the board of directors of our general partner.

Director Independence

Each of W. Wesley Perry and W. Duncan Kennedy is independent within the meaning of the rules of NASDAQ. In accordance with the rules of NASDAQ, Diamondback will appoint one additional independent member within one year of the effective date of the registration statement relating to our IPO.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee and a conflicts committee. We do not have a compensation committee, but rather that the board of directors of our general partner has authority over compensation matters.

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 NASDAQ and Rule 10A-3 promulgated under the Exchange Act, subject to certain transitional relief during the one-year period following consummation of the IPO as described above. W. Wesley Perry and W. Duncan Kennedy serve as the initial members of the audit committee. The audit committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee has 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 also is responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has unrestricted access to the audit committee and our management, as necessary.

Conflicts Committee

Our conflicts committee reviews specific matters that the board believes may involve conflicts of interest and determines to submit to the conflicts committee for review. The conflicts committee determines if the resolution of the conflict of interest is in our best 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, including Diamondback, and must meet the independence standards established by NASDAQ 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 it may owe us or our unitholders. We have not yet appointed a director to our conflicts committee.

Indemnification Agreements

We and our general partner have entered into indemnification agreements with each of the current directors and executive officers of our general partner. These agreements require us to indemnify these individuals to the fullest extent permitted by law against expenses incurred as a result of any proceeding in which they are involved by reason of their service to us and, if requested, to advance expenses incurred as a result of any such proceeding. We also intend to enter into indemnification agreements with future directors and executive officers of our general partner.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

Compensation Discussion and Analysis

We are a new subsidiary of Diamondback, formed in February 2014, consisting of certain assets that Diamondback contributed to us in connection with the IPO. Accordingly, neither we nor our general partner incurred any cost or liability with respect to management compensation or retirement benefits for directors or executive officers for any periods prior to our formation date. As a result, we have no historical compensation information to present. We currently do not have a compensation committee.

Our general partner has the sole responsibility for conducting our business and for managing our operations, and its board of directors and executive officers make decisions on our behalf. We do not and will not directly employ any of the persons responsible for managing our business. Our executive officers are employed and compensated by Diamondback or a subsidiary of Diamondback. All of the executive officers that are responsible for managing our day-to-day affairs are also current executive officers of Diamondback.

All of the executive officers of our general partner have responsibilities to both us and Diamondback, and we expect that our executive officers allocate their time between managing our business and managing the business of Diamondback. Since all of our executive officers are employed by Diamondback or one of its subsidiaries, the responsibility and authority for compensation-related decisions for our executive officers will reside with the Diamondback compensation committee. Diamondback has the ultimate decision-making authority with respect to the total compensation of the executive officers that are employed by Diamondback including, subject to the terms of the partnership agreement, the portion of that compensation that is allocated to us pursuant to Diamondback's allocation methodology. Any such compensation decisions will not be subject to any approvals by the board of directors of our general partner or any committees thereof. However, all determinations with respect to awards that may be made to our executive officers, key employees, and independent directors under the LTIP or any other long-term incentive plan we adopt will be made by the board of directors of our general partner or a committee thereof that may be established for such purpose. Please see the description of the LTIP below under the heading "Long-Term Incentive Plan."

The executive officers of our general partner, as well as the employees of Diamondback who provide services to us, may participate in employee benefit plans and arrangements sponsored by Diamondback, including plans that may be established in the future. Certain of our general partner's executive officers and employees and certain employees of Diamondback who provide services to us currently hold grants under Diamondback's equity incentive plans. Except with respect to any awards that may be granted under the LTIP, our executive officers do not receive separate amounts of compensation in relation to the services they provide to us. In accordance with the terms of our partnership agreement, we will reimburse Diamondback for compensation related expenses attributable to the portion of the executive's time dedicated to providing services to us. Please read "The Partnership Agreement—Reimbursement of Expenses." Although we will bear an allocated portion of Diamondback's costs of providing compensation and benefits to employees who serve as executive officers of our general partner, we will have no control over such costs and will not establish or direct the compensation policies or practices of Diamondback. Except with respect to any awards granted under the LTIP, we expect that compensation paid or awarded by us in 2014 will consist only of the portion of compensation paid by Diamondback that is allocated to us and our general partner pursuant to Diamondback's allocation methodology and subject to the terms of the partnership agreement.

On June 17, 2014, we granted an aggregate of 2,500,000 unit options under the LTIP to our executive officers. Each unit option entitles the recipient to purchase one of our common units. In accordance with the LTIP, the exercise price of the unit options granted may not be less than the market value of our common units on the date of grant. Subject to accelerated vesting upon certain specified events, a third of the unit options will vest each year, and the options will be automatically exercised, to the extent vested, on the earlier to occur of the three year anniversary of the date of grant or the occurrence of a change in control.

We expect that future compensation for our executive officers will be structured in a manner similar to that currently used by Diamondback to compensate its named executive officers. In the future, as Diamondback and our general partner formulate and implement the compensation programs for our executive officers, Diamondback, our general partner or both may provide different or additional compensation components, benefits or perquisites to our executive officers, to ensure they are provided with a balanced, comprehensive and competitive compensation structure.

Long-Term Incentive Plan

In order to incentivize our management and directors to continue to grow our business, the board of directors of our general partner adopted the LTIP for employees, officers, consultants and directors of our general partner and any of its affiliates, including Diamondback, who perform services for us.

The description of the LTIP set forth below is a summary of the material features of the LTIP. This summary, however, does not purport to be a complete description of all the provisions of the LTIP and is qualified in its entirety by reference to the LTIP, which is filed as an exhibit to this registration statement of which this prospectus forms a part. The purpose of the LTIP is to provide a means to attract and retain individuals who are essential to our growth and profitability and to encourage them to devote their best efforts to advancing our business by affording such individuals a means to acquire and maintain ownership of awards, the value of which is tied to the performance of our common units. The LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards (collectively, "awards"). These awards are intended to align the interests of employees, officers, consultants and directors with those of our unitholders and to give such individuals the opportunity to share in our long-term performance. Any awards that are made under the LTIP will be approved by the board of directors of our general partner or a committee thereof that may be established for such purpose. We will be responsible for the cost of awards granted under the LTIP.

Administration

The LTIP is administered by the board of directors of our general partner or an alternative committee appointed by the board of directors of our general partner, which we refer to together as the "committee" for purposes of this summary. The committee administers the LTIP pursuant to its terms and all applicable state, federal, or other rules or laws. The committee has the power to determine to whom and when awards will be granted, determine the amount of awards (measured in cash or in shares of our common units), proscribe and interpret the terms and provisions of each award agreement (the terms of which may vary), accelerate the vesting provisions associated with an award, delegate duties under the LTIP and execute all other responsibilities permitted or required under the LTIP. In the event that the committee is not comprised of "nonemployee directors" within the meaning of Rule 16b-3 under the Exchange Act, the full board of directors or a subcommittee of two or more nonemployee directors will administer all awards granted to individuals that are subject to Section 16 of the Exchange Act.

Securities to be Offered

The maximum aggregate number of common units that may be issued pursuant to any and all awards under the LTIP shall not exceed 9,144,000 common units, subject to adjustment due to recapitalization or reorganization, or related to forfeitures or expiration of awards, as provided under the LTIP.

If any common units subject to any award are not issued or transferred, or cease to be issuable or transferable for any reason, including (but not exclusively) because units are withheld or surrendered in payment of taxes or any exercise or purchase price relating to an award or because an award is forfeited, terminated, expires unexercised, is settled in cash in lieu of common units, or is otherwise terminated without a delivery of units, those common units will again be available for issue, transfer, or exercise pursuant to awards under the LTIP, to the extent allowable by law. Common units to be delivered pursuant to awards under our LTIP may be common units acquired by our general partner in the open market, from any other person, directly from us, or any combination of the foregoing.

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Awards

Unit Options

We may grant unit options to eligible persons. Unit options are rights to acquire common units at a specified price. The exercise price of each unit option granted under the LTIP will be stated in the unit option agreement and may vary; provided, however, that, the exercise price for an unit option must not be less than 100% of the fair market value per common unit as of the date of grant of the unit option unless that unit option is intended to otherwise comply with the requirements of Section 409A of the Internal Revenue Code of 1986, as amended, or the Code. Unit options may be exercised in the manner and at such times as the committee determines for each unit option, unless that unit option is determined to be subject to Section 409A of the Code, in which case the unit option will be subject to any necessary timing restrictions imposed by the Code or federal regulations. The committee will determine the methods and form of payment for the exercise price of a unit option and the methods and forms in which common units will be delivered to a participant.

Unit Appreciation Rights

A unit appreciation right is the right to receive, in cash or in common units, as determined by the committee, an amount equal to the excess of the fair market value of one common unit on the date of exercise over the grant price of the unit appreciation right. The committee will be able to make grants of unit appreciation rights and will determine the time or times at which a unit appreciation right may be exercised in whole or in part. The exercise price of each unit appreciation right granted under the LTIP will be stated in the unit appreciation right agreement and may vary; provided, however, that, the exercise price must not be less than 100% of the fair market value per common unit as of the date of grant of the unit appreciation right, unless that unit appreciation right is intended to otherwise comply with the requirements of Section 409A of the Code.

Restricted Units

A restricted unit is a grant of a common unit subject to a risk of forfeiture, performance conditions, restrictions on transferability and any other restrictions imposed by the committee in its discretion. Restrictions may lapse at such times and under such circumstances as determined by the committee. The committee shall provide, in the restricted unit agreement, whether the restricted unit will be forfeited upon certain terminations of employment. Unless otherwise determined by the committee, a common unit distributed in connection with a unit split or unit dividend, and other property distributed as a dividend, will generally be subject to restrictions and a risk of forfeiture to the same extent as the restricted unit with respect to which such common unit or other property has been distributed.

Unit Awards

The committee is authorized to grant common units that are not subject to restrictions. The committee may grant unit awards to any eligible person in such amounts as the committee, in its sole discretion, may select.

Phantom Units

Phantom units are rights to receive common units, cash or a combination of both at the end of a specified period. The committee may subject phantom units to restrictions (which may include a risk of forfeiture) to be specified in the phantom unit agreement that may lapse at such times determined by the committee. Phantom units may be satisfied by delivery of common units, cash equal to the fair market value of the specified number of common units covered by the phantom unit or any combination thereof determined by the committee. Except as otherwise provided by the committee in the phantom unit agreement or otherwise, phantom units subject to forfeiture restrictions may be forfeited upon termination of a participant’s employment prior to the end of the specified period. Cash distribution equivalents may be paid during or after the vesting period with respect to a phantom unit, as determined by the committee.

Distribution Equivalent Rights

The committee is able to grant distribution equivalent rights in tandem with awards under the LTIP (other than unit awards or an award of restricted units), or distribution equivalent rights may be granted alone. Distribution equivalent rights entitle the participant to receive cash equal to the amount of any cash distributions made by us during the period the distribution equivalent right is outstanding. Payment of cash distributions pursuant to a distribution equivalent right issued in connection with another award may be subject to the same vesting terms as the award to which it relates or different vesting terms, in the discretion of the committee.

Cash Awards

The LTIP permits the grant of awards denominated in and settled in cash. Cash awards may be based, in whole or in part, on the value or performance of a common unit.

Performance Awards

The committee may condition the right to exercise or receive an award under the LTIP, or may increase or decrease the amount payable with respect to an award, based on the attainment of one or more performance conditions deemed appropriate by the committee.

Other Unit-Based Awards

The LTIP permits the grant of other unit-based awards, which are awards that may be based, in whole or in part, on the value or performance of a common unit or are denominated or payable in common units. Upon settlement, these other unit-based awards may be paid in common units, cash or a combination thereof, as provided in the award agreement.

Substitute Awards

The LTIP permits the grant of awards in substitution for similar awards held by individuals who become employees, consultants or directors as a result of a merger, consolidation, or acquisition by or involving us, an affiliate of another entity, or the assets of another entity. Such substitute awards that are unit options or unit appreciation rights may have exercise prices less than 100% of the fair market value per common unit on the date of the substitution if such substitution complies with Section 409A of the Code and its regulations and other applicable laws and exchange rules.

Miscellaneous

Tax Withholding

At our discretion, and subject to conditions that the committee may impose, a participant's minimum statutory tax withholding with respect to an award may be satisfied by withholding from any payment related to an award or by the withholding of common units issuable pursuant to the award based on the fair market value of the common units.

Anti-Dilution Adjustments

If any "equity restructuring" event occurs that could result in an additional compensation expense under Financial Accounting Standards Board Accounting Standards Codification Topic 718 ("FASB ASC Topic 718") if adjustments to awards with respect to such event were discretionary, the committee will equitably adjust the number and type of units covered by each outstanding award and the terms and conditions of each such award to equitably reflect the restructuring event. With respect to a similar event that would not result in a FASB ASC Topic 718 accounting charge if adjustment to awards were discretionary, the committee shall have complete discretion to adjust awards in the manner it deems appropriate. In the event the committee makes any adjustment in accordance with the foregoing provisions, a corresponding and proportionate adjustment shall be made with respect to the maximum number of units available under the LTIP and the kind of units or other securities available for grant under the LTIP. Furthermore, in the case of (i) a subdivision or consolidation of the common units (by reclassification, split or reverse split or otherwise), (ii) a recapitalization, reclassification, or other change in our capital structure or (iii) any other reorganization, merger, combination, exchange, or other relevant change in capitalization of our equity, then a corresponding and proportionate adjustment shall be made in accordance with the terms of the LTIP, as appropriate, with respect to the maximum number of units available under the LTIP, the number of units that may be acquired with respect to an award, and, if applicable, the exercise price of an award, in order to prevent dilution or enlargement of awards as a result of such events.

Change in Control

Upon a “change in control” (as defined in the LTIP), the committee may, in its discretion, (i) remove any forfeiture restrictions applicable to an award, (ii) accelerate the time of exercisability or vesting of an award, (iii) require awards to be surrendered in exchange for a cash payment, (iv) cancel unvested awards without payment or (v) make adjustments to awards as the committee deems appropriate to reflect the change in control.

Termination of Employment or Service

The consequences of the termination of a participant’s employment, consulting arrangement or membership on the board of directors will be determined by the committee in the terms of the relevant award agreement.

Director Compensation

We and our general partner were formed in February 2014 and, as such, have not accrued or paid any obligations with respect to compensation for directors for any periods prior to our formation date.

The executive officers or employees of our general partner or of Diamondback who also serve as directors of our general partner do not receive additional compensation for their service as a director of our general partner. Directors of our general partner who are not executive officers or employees of our general partner or of Diamondback receive compensation as “non-employee directors” as set by our general partner’s board of directors.

Each non-employee director receives a compensation package that consists of an annual cash retainer of $47,500 plus an additional annual payment of $15,000 for the chairperson and $10,000 for each other member of the audit committee and $10,000 for the chairperson and $5,000 for each other member of each other committee. Our directors also receive a fee of $1,000 for attending each in-person meeting of the board of directors or its committees and $500 for attending each telephone meeting. In addition, our directors will be reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees. Each non-employee director may receive grants of equity-based awards under the LTIP from time to time for so long as he or she serves as a director.

Each member of the board of directors of our general partner will be indemnified for his actions associated with being a director to the fullest extent permitted under Delaware law.

SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table presents information regarding the beneficial ownership of our common units as of August 31, 2014 by:

- our general partner;
- each of our general partner's directors and 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 500 West Texas Avenue, Suite 1200, Midland, Texas 79701.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Diamondback(1)	70,450,000	92%
Viper Energy Partners GP LLC	—	—
Travis D. Stice	37,500	*
Teresa L. Dick	10,000	*
Russell Pantermuehl	30,000	*
Randall J. Holder	5,000	*
Steven E. West	—	—
W. Wesley Perry	20,000	*
W. Duncan Kennedy	—	—
Michael L. Hollis	50,000	*
James L. Rubin	—	—
All directors and executive officers as a group (9 persons)	—	—

* Less than 1%

(1) Diamondback Energy, Inc. is a publicly traded company. The directors of Diamondback are Travis D. Stice, Steven E. West, Michael P. Cross, David L. Houston and Mark L. Plaumann.

The following table sets forth, as of August 31, 2014, the number of shares of common stock of Diamondback beneficially owned by Wexford and each of the directors and executive officers of our general partner and all directors and executive officers of our general partner as a group.

	Shares of Diamondback Common Stock Beneficially Owned(1)	
Name of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percentage of Class
DB Energy Holdings LLC(2)	8,134,376	14.4%
Travis D. Stice(3)	28,991	*
Teresa L. Dick(4)	24,484	*
Russell Pantermuehl(5)	36,497	*
Randall J. Holder(6)	—	—
Steven E. West	2,802	*
W. Wesley Perry	—	—
W. Duncan Kennedy	—	—
Michael L. Hollis(7)	39,542	*
James L. Rubin	—	—
All directors and executive officers as a group (9 persons)	132,316	*

* Less than 1%

(1) Beneficial ownership is determined in accordance with SEC rules. In computing percentage ownership of each person, shares of common stock subject to options held by that person that are exercisable as of August 31, 2014, or exercisable within 60 days of August 31, 2014, are deemed to be beneficially owned. These shares, however, are not deemed outstanding for the purpose of computing the percentage ownership of each other person. The percentage of shares beneficially owned is based on 56,636,921 shares of common stock outstanding as of August 31, 2014. Unless otherwise indicated, all amounts exclude shares issuable upon the exercise of outstanding options and vesting of restricted stock units that are not exercisable and/or vested as of August 31, 2014 or within 60 days of August 31, 2014.

(2) Based solely on Schedule 13D/A filed with the SEC on June 27, 2014 by DB Energy Holdings LLC ("DB Holdings"), Wexford Spectrum Fund, L.P. ("WSF"), Wexford Catalyst Fund, L.P. ("WCF"), Spectrum Intermediate Fund Limited ("SIF"), Catalyst Intermediate Fund Limited ("CIF," and together with DB Holdings, WSF, WCF and SIF, the "Funds"), Wexford, Wexford GP LLC ("Wexford GP"), Charles E. Davidson ("Mr. Davidson"), and Joseph M. Jacobs ("Mr. Jacobs"). DB Holdings is a holding company managed by Wexford. WSF, WCF, SIF and CIF are investment funds managed by Wexford. Wexford is an investment advisor registered with the SEC, and manages a series of investment funds. Wexford GP is the general partner of Wexford. Mr. Davidson and Mr. Jacobs are the managing members of Wexford GP. DB has shared voting and dispositive power over 8,134,376 shares. WSF has shared voting and dispositive power over 97,048 shares. WCF has shared voting and dispositive power over 15,335 shares. SIF has shared voting and dispositive power over 321,030 shares. CIF has shared voting and dispositive power over 60,158 shares. Wexford, Wexford GP, Mr. Davidson and Mr. Jacobs have shared voting and dispositive power over 8,634,613 shares. Wexford may, by reason of its status as manager or investment manager of the Funds, be deemed to own beneficially the securities of which the Funds possess beneficial ownership. Wexford GP may, as the General Partner of Wexford, be deemed to own beneficially the securities of which the Funds possess beneficial ownership. Each of Mr. Davidson and Mr. Jacobs may, by reason of his status as a controlling person of Wexford GP, be deemed to own beneficially the securities of which the Funds possess beneficial ownership. Each of Wexford, Wexford GP, Mr. Davidson and Mr. Jacobs disclaims beneficial ownership of the securities owned by the Funds except, in the case of Mr. Davidson and Mr. Jacobs, to the extent of their respective interests in the Funds.

(3) Excludes options to purchase 75,000 shares of Diamondback common stock, which will vest on April 18, 2015, and 30,953 restricted stock units, of which 14,286 will vest on April 18, 2015 and 16,667 will vest in two remaining approximately equal annual installments beginning on January 2, 2015. Also excludes 25,000 performance-based restricted stock units awarded to Mr. Stice on February 27, 2014, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group.

(4) Includes shares issuable upon exercise of options to purchase 19,410 shares of Diamondback common stock and 4,286 restricted stock units, all of which have vested or will vest within 60 days of August 31, 2014, and 788 shares of Diamondback common stock held by Ms. Dick. Excludes options to purchase 12,500 shares of common stock, which will vest on September 1, 2015, and 9,006 restricted stock units, of which 4,286 will vest on September 1, 2015 and 4,720 will vest in two equal annual installments beginning on January 2, 2015. Also excludes 7,080 performance-based restricted stock units awarded to Ms. Dick on February 27, 2014, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group.

(5) Includes shares issuable upon exercise of options to purchase 25,000 shares of Diamondback common stock and 8,572 restricted stock units, all of which have vested or will vest within 60 days of August 31, 2014, and 2,925 shares of Diamondback common stock held by Mr. Pantermuehl. Excludes options to purchase 25,000 shares of common stock, which will vest on August 15, 2015, and 14,422 restricted stock units, of which 8,572 will vest on August 15, 2015 and 5,850 will vest in two equal annual installments beginning on January 2, 2015. Also excludes 8,775 performance-based restricted stock units awarded to Mr. Pantermuehl on February 27, 2014, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group.

(6) Excludes options to purchase 25,000 shares of common stock, which will vest in two equal annual installments beginning on November 18, 2014, and 13,132 restricted stock units, of which 8,572 will vest in two equal annual installments beginning on November 18, 2014 and 4,560 will vest in two equal annual installments beginning on January 2, 2015. Also excludes 6,840 performance-based restricted stock units awarded to Mr. Holder on February 27, 2014, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group.

(7) Includes shares issuable upon exercise of options to purchase 28,045 shares of Diamondback common stock and 8,572 restricted stock units, all of which have vested or will vest within 60 days of August 31, 2014, and 25,000 shares of Diamondback common stock held by Mr. Hollis. Excludes options to purchase 25,000 shares of Diamondback common stock, which will vest on September 12, 2015, and 14,422 restricted stock units, of which 8,572 will vest on September 12, 2015 and 5,850 will vest in two equal annual installments beginning on January 2, 2015. Also excludes 8,775 performance-based restricted stock units awarded to Mr. Hollis on February 27, 2014, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to the Diamondback's peer group.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Diamondback owns 70,450,000 common units, representing approximately 92% of our outstanding units prior to the completion of this offering, and our general partner owns a non-economic general partner interest in us that does not entitle it to receive distributions.

The terms of the transactions and agreements disclosed in this section were determined by and among affiliated entities and, consequently, are not the result of arm's length negotiations. These terms are not necessarily at least as favorable to the parties to these transactions and agreements as the terms that could have been obtained from unaffiliated third parties.

Distributions and Payments to Diamondback and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to Diamondback and its affiliates (including our general partner) in connection with the formation, ongoing operation and any liquidation of Diamondback.

Formation Stage	
The consideration received by Diamondback for the contribution of its interests in Viper Energy Partners LLC	Ÿ 70,450,000 common units; and Ÿ approximately $137.5 million of the net proceeds of the IPO.
Operational Stage	
Payments to our general partner and its affiliates	We reimburse our general partner and its affiliates for all expenses incurred on our behalf. We and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford will provide general finance and advisory services in exchange for a fee and certain expense reimbursement.
Cash distributions to Diamondback and its affiliates	We will generally make cash distributions 100% to our unitholders, including affiliates of our general partner, pro rata.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its non-economic general partner interest will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of the interest. Please read "The Partnership Agreement—Withdrawal or Removal of Our General Partner."
Liquidation Stage	
Liquidation	Upon our liquidation, our unitholders will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements and Transactions with Affiliates

We have entered into certain agreements and transactions with Diamondback and its affiliates, as described in more detail below.

Contribution Agreement

On June 17, 2014, in connection with the closing of the IPO, we entered into a contribution agreement that effected, among other things, the transfer of the ownership interests in Viper Energy Partners LLC to us in exchange for 70,450,000 common units issued to Diamondback and our agreement to distribute to Diamondback all cash and the royalty income receivable on hand at the time of the IPO and the net proceeds from the IPO. As of June 30, 2014, we had distributed $137.5 million to Diamondback and recorded a payable balance of approximately $11.3 million. While we believe this agreement is on terms no less favorable to any party than those that could have been negotiated with an unaffiliated third party, it was not the result of arm's-length negotiations. All of the transaction expenses incurred in connection with these transactions were paid from the proceeds of the IPO.

Registration Rights Agreement

On June 23, 2014, in connection with the IPO, we entered into a registration rights agreement with Diamondback. Pursuant to the registration rights agreement, we are required to file a registration statement to register the common units issued to Diamondback. The registration rights agreement also includes provisions dealing with holdback agreements, indemnification and contribution and allocation of expenses. These registration rights are transferable to affiliates and, in certain circumstances, to third parties. Please read "Units Eligible for Future Sale."

Advisory Services Agreement

On June 23, 2014, in connection with the closing of the IPO, we entered into an advisory services agreement with Wexford under which Wexford will provide us and our general partner with general financial and strategic advisory services related to our business in return for an annual fee of $500,000, plus reimbursement of reasonable out-of-pocket expenses. This annual fee does not cover any advisory services related to acquisitions, divestitures, financings or other transactions in which we may be involved in the future. In addition, under this agreement, we will pay Wexford to-be-negotiated market-based fees approved by the conflicts committee of the board of directors of our general partner for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions in which we may be involved. This agreement has a term of two years commencing on the completion of the IPO. The agreement will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. The agreement may be terminated at any time by either party upon 30 days' prior written notice. In the event we terminate the agreement, we will be obligated to pay all amounts due through the remaining term of the agreement. The services provided by Wexford under the advisory services agreement do not extend to our day-to-day business or operations. In this agreement, we indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. In the event we are dissatisfied with the services provided by Wexford, our only remedy against Wexford is to terminate the agreement.

Tax Sharing Agreement

On June 23, 2014, in connection with the closing of the IPO, we entered into a tax sharing agreement with Diamondback pursuant to which we are required to reimburse Diamondback for our share of state and local income and other taxes borne by Diamondback as a result of our results being included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on the closing date of the IPO. The amount of any such reimbursement is limited to the tax that we would have paid had we not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which we may be a member for this purpose, to owe no tax. However, we would nevertheless reimburse Diamondback for the tax we would have owed had the attributes not been available or used for our benefit, even though Diamondback had no cash expense for that period.

Other Transactions with Related Persons

On September 18, 2013, Diamondback completed an offering of $450 million in aggregate principal amount of 7.625% senior unsecured notes due 2021, in connection with which Viper Energy Partners LLC is a subsidiary guarantor. In connection with the closing of the IPO, Viper Energy Partners LLC was released from this guarantee.

Effective September 19, 2013, we issued a subordinated note to Diamondback for the principal sum of $440 million for the acquisition of our mineral interests. The note bore interest at 7.625% per annum. Interest was due and payable monthly in arrears on the first business day of each calendar month. The unpaid principal balance and all accrued interest on the note were due and payable in full on October 1, 2021. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under Diamondback's revolving credit facility. As of December 31, 2013, there was $440 million outstanding under this note. During the six months ended June 30, 2014 and the period from inception (September 18, 2013) to December 31, 2013, we incurred approximately $10.7 and $5.7 million of net interest expense, respectively. We owed no amounts and $9.7 million of accrued interest as of June 30, 2014 and December 31, 2013, respectively. In connection with the IPO, the subordinated note was converted into equity.

Effective September 19, 2013, we entered into a shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback. Under this agreement, Diamondback E&P LLC provides consulting and administrative services to us. We incurred a monthly charge for the services of $26,000 or other amounts that are otherwise mutually agreed to in writing between Diamondback E&P LLC and us. For the six months ended June 30, 2014 and the period from inception (September 18, 2013) to December 31, 2013, we incurred $156,000 and $87,000, respectively, for services under this agreement. At June 30, 2014 and December 31, 2013, we owed Diamondback E&P LLC no amounts and $87,000, respectively. This agreement was terminated at the closing of the IPO.

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

The board of directors of our general partner has adopted policies for the review, approval and ratification of transactions with related persons. The board has adopted a written code of business conduct and ethics, under which a director is 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 such 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.

If a conflict or potential conflict of interest arises between our general partner or its affiliates, on the one hand, and us or our unitholders, on the other hand, the resolution of any such conflict or potential conflict should be addressed by the board of directors of our general partner in accordance with the provisions of our partnership agreement. At the discretion of the board in light of the circumstances, the resolution may be determined by the board in its entirety or by a conflicts committee meeting the definitional requirements for such a committee under our partnership agreement.

Any executive officer is required to avoid conflicts of interest unless approved by the board of directors of our general partner.

Please read "Conflicts of Interest and Fiduciary Duties—Conflicts of Interest" for additional information regarding the relevant provisions of our partnership agreement.

The code of business conduct and ethics described above was adopted in connection with the closing of the IPO, and as a result, the transactions described above were not reviewed according to such procedures.

CONFLICTS OF INTEREST AND 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 to the limited partners and the partnership. Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. Our partnership agreement also specifically defines the remedies available to unitholders for actions taken that, without these defined liability standards, might constitute breaches of fiduciary duty under applicable Delaware law.

When our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in “good faith,” meaning it must not act in a manner that it believes 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 will not be subject to any higher standard.

Our partnership agreement specifies decisions that our general partner may make in its individual capacity, and permits our general partner to make these decisions free of any contractual or other duty to us or our unitholders. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its call right, its voting rights with respect to any units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation or amendment of the partnership agreement.

When the directors and officers of our general partner cause our general partner to manage and operate our business, the directors and officers must cause our general partner to act in a manner consistent with our general partner’s applicable duties. However, the directors and officers of our general partner have fiduciary duties to manage our general partner, including when it is acting in its capacity as our general partner, in a manner beneficial to Diamondback.

Conflicts may arise as a result of the duties of our general partner and its directors and officers to act for the benefit of its owners, which may conflict with our interests and the interests of our public unitholders. Where the directors and officers of our general partner are causing our general partner to act in its capacity as our general partner, the directors and officers must cause the general partner to act in good faith, meaning they cannot cause the general partner to take an action that they believe is adverse to our interest. However, where a decision by our general partner in its capacity as our general partner is not clearly not adverse to our interest, the directors of our general partner may determine to submit the determination to the conflicts committee for review or to seek approval by the unitholders, as described below.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its directors, executive officers and owners (including Diamondback), on the one hand, and us and our limited partners, on the other hand.

Whenever a conflict arises between our general partner or its owners, on the one hand, and us or our limited partners, on the other hand, the resolution, course of action or transaction in respect of such conflict of interest shall be conclusively deemed approved by us and all our limited partners and shall not constitute a breach of our partnership agreement, of any agreement contemplated thereby or of any duty, if the resolution or course of action or transaction in respect of such conflict of interest is:

- approved by the conflicts committee of our general partner; or
- approved by the holders of a majority of the outstanding common units, excluding any such units owned by our general partner or any of its affiliates.

Our general partner may, but is not required to, seek the approval of such resolutions or courses of action from the conflicts committee of its board of directors or from the holders of a majority of the outstanding common units as described above. If our general partner does not seek approval from the conflicts committee or from holders of common units as described above and 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 board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of us or any of our unitholders, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith. Unless the resolution of a conflict is specifically provided for in our partnership agreement, the board of directors of our general partner or the conflicts committee of the board of directors of our general partner may consider any factors they determine in good faith to consider when resolving a conflict. An independent third party is not required to evaluate the resolution. Under our partnership agreement, all determinations, other actions or failures to act by our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) will be presumed to be "in good faith," and in any proceeding brought by or on behalf of us or any of our unitholders, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith. Please read "Management—Committees of the Board of Directors—Conflicts Committee" for information about the conflicts committee of our general partner's board of directors.

Conflicts of interest could arise in the situations described below, among others:

Actions taken by our general partner may affect the amount of cash available to pay distributions to unitholders.

The amount of cash that is available for distribution to unitholders is affected by decisions of our general partner regarding such matters as:

- amount and timing of asset purchases and sales;
- cash expenditures;
- borrowings;
- entry into and repayment of current and future indebtedness;
- issuance of additional units; and
- the creation, reduction or increase of reserves.

Our partnership agreement permits us to borrow funds to make a distribution, and further provides that we and our subsidiaries may borrow funds from our general partner and its affiliates.

The directors and executive officers of our general partner who are also officers and directors of Diamondback have a fiduciary duty to make decisions in the best interests of the owners of Diamondback, which may be contrary to our interests.

The executive officers and certain directors of our general partner are also officers and directors of Diamondback. These officers and directors have fiduciary duties to Diamondback that may cause them to pursue business strategies that disproportionately benefit Diamondback or which otherwise are not in our best interests.

Our general partner is allowed to take into account the interests of parties other than us, such as Diamondback, in exercising certain rights under our partnership agreement.

Our partnership agreement contains provisions that replace the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or any limited partner. Examples include the exercise of its call right, its voting rights with respect to any units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the partnership or amendment of the partnership agreement.

Our partnership agreement restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

In addition to the provisions described above, our partnership agreement contains provisions that have the effect of restricting the remedies available to our unitholders for actions that might otherwise constitute breaches of fiduciary duty. For example, our partnership agreement provides that:

- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it did not believe that the decision was adverse to the interests of the partnership;
- our general partner and its officers and directors will not be liable for monetary damages or otherwise to us or our limited partners for any losses sustained or liabilities incurred as a result of the general partner's, officer's or director's determinations, acts or omissions in their capacities as general partner, officers or directors, unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such losses or liabilities were the result of the conduct of our general partner or such officer or director engaged by it in bad faith, willful misconduct or fraud or, with respect to any criminal conduct, with knowledge that such conduct was unlawful; and
- in resolving conflicts of interest, it will be presumed that in making its decision our general partner, the board of directors of our general partner or the conflicts committee of the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith.

By purchasing a common unit, a common unitholder will agree to become bound by the provisions in our partnership agreement, including the provisions discussed above. Please read "—Fiduciary Duties."

Common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us.

Any agreements between us, on the one hand, and our general partner and its affiliates, on the other, will not grant to the unitholders, separate and apart from us, the right to enforce the obligations of our general partner and its affiliates in our favor.

Contracts between us, on the one hand, and our general partner and its affiliates, on the other, are not and will not be the result of arm's-length negotiations.

Neither our partnership agreement nor any of the other agreements, contracts and arrangements between us and our general partner and its affiliates are or will be the result of arm's-length negotiations. Our general partner will determine, in good faith, the terms of any of such future transactions.

Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.

Under our partnership agreement, our general partner has full power and authority to do all things, other than those items that require unitholder approval, necessary or appropriate to conduct our business including, but not limited to, the following actions:

- expending, lending, or borrowing money, assuming, guaranteeing, or otherwise contracting for, indebtedness and other liabilities, issuing evidences of indebtedness, including indebtedness that is convertible into our securities, and incurring any other obligations;

- preparing and transmitting tax, regulatory and other filings, periodic or other reports to governmental or other agencies having jurisdiction over our business or assets;
- acquiring, disposing, mortgaging, pledging, encumbering, hypothecating, or exchanging our assets or merging or otherwise combining us with or into another person;
- negotiating, executing and performing contracts, conveyance or other instruments;
- distributing cash;
- selecting or dismissing employees and agents, outside attorneys, accountants, consultants and contractors and determining their compensation and other terms of employment or hiring;
- maintaining insurance for our benefit;
- forming, acquiring an interest in, and contributing property and loaning money to, any further limited partnerships, joint ventures, corporations, limited liability companies or other entities;
- controlling all matters affecting our rights and obligations, including bringing and defending actions at law or in equity or otherwise litigating, arbitrating or mediating, and incurring legal expense and settling claims and litigation;
- indemnifying any person against liabilities and contingencies to the extent permitted by law;
- purchasing, selling or otherwise acquiring or disposing of our partnership interests, or issuing additional options, rights, warrants, appreciation rights, phantom or tracking interests relating to our partnership interests; and
- entering into agreements with any of its affiliates to render services to us or to itself in the discharge of its duties as our general partner.

Please read “The Partnership Agreement” for information regarding the voting rights of unitholders.

Our general partner determines which of the costs it incurs on our behalf are reimbursable by us.

We reimburse our general partner and its affiliates for the costs incurred in managing and operating us, including costs incurred in rendering corporate staff and support services to us. Our partnership agreement provides that our general partner will determine such other expenses that are allocable to us, and neither the partnership agreement nor the advisory services agreement limits the amount of expenses for which our general partner and its affiliates may be reimbursed. Please read “Certain Relationships and Related Party Transactions—Agreements and Transactions with Affiliates.”

Common units are subject to our general partner’s call right.

If at any time our general partner and its affiliates (including Diamondback) own more than 97% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at the market price calculated in accordance with the terms of our partnership agreement. If our general partner and its affiliates (including Diamondback) reduce their ownership to below 75% of the outstanding common units, the ownership threshold to exercise the call right will be permanently reduced to 80%. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. Our general partner may use its own discretion, free of fiduciary duty restrictions, in determining whether to exercise this right. As a result, a common unitholder may have his common units purchased from him at an undesirable time or price. Please read “The Partnership Agreement—Limited Call Right.”

We may choose to not retain separate counsel for ourselves or for the holders of common units.

The attorneys, independent accountants and others who perform services for us have been retained by our general partner. Attorneys, independent accountants and others who perform services for us are selected by our general partner or the conflicts committee of the board of directors of our general partner and may perform services for our general partner and its affiliates. We may retain separate counsel for ourselves or the conflict committee in the event of a conflict of interest between our general partner and its affiliates, on the one hand, and us or the holders of common units, on the other, depending on the nature of the conflict, although we may choose not to do so.

Our general partner's affiliates may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Our partnership agreement provides that our general partner is restricted from engaging in any business activities other than acting as our general partner, engaging in activities incidental to its ownership interest in us and providing management, advisory, and administrative services to its affiliates or to other persons. However, affiliates of our general partner, including Diamondback and Wexford, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, Diamondback and Wexford may compete with us for investment opportunities and may own an interest in entities that compete with us. Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers and directors and Diamondback and Wexford. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us.

Fiduciary Duties

Duties owed to unitholders by our general partner 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 otherwise owed by the general partner to limited partners and the partnership.

Our partnership agreement contains various provisions eliminating the fiduciary duties that might otherwise be owed by our general partner and replacing them with contractual standards of conduct. We have adopted these provisions to allow our general partner or its affiliates to engage in transactions with us that otherwise might be prohibited by state law fiduciary standards and to take into account the interests of other parties in addition to our interests when resolving conflicts of interest. We believe this is appropriate and necessary because the board of directors of our general partner has a duty to manage our partnership in good faith and a duty to manage our general partner in a manner beneficial to its owner. Without these modifications, our general partner's ability to make decisions involving conflicts of interest would be restricted. The provisions eliminating and replacing the default fiduciary standards benefit our general partner by enabling it to take into consideration all parties involved in the proposed action. These provisions also strengthen the ability of our general partner to attract and retain experienced and capable directors. These provisions represent a detriment to our public unitholders because they restrict the remedies available to our public unitholders for actions that, without those provisions, might constitute breaches of fiduciary duty, as described below, and permit our general partner to take into account the interests of third parties in addition to our interests when resolving conflicts of interests. The following is a summary of:

- the default fiduciary duties under by the Delaware Act;
- the 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.

State law fiduciary duty standards	Fiduciary duties are generally considered to include an obligation to act in good faith and with due care and 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 for the partnership in the same manner as a prudent person would act on his own behalf. The duty of loyalty, in the absence of a provision in a partnership agreement providing otherwise, would generally require that any action taken or transaction engaged in be entirely fair to the partnership.
Partnership agreement modified standards	Our partnership agreement contains provisions that waive or consent to conduct by our general partner and its affiliates that might otherwise raise issues as to compliance with fiduciary duties or applicable law. For example, our partnership agreement provides that when our general partner is acting in its capacity as our general partner, as opposed to in its individual capacity, it must act in “good faith,” meaning that it believed its actions or omissions were not adverse to the interests of the partnership, and will not be subject to any other standard under applicable law. In addition, when our general partner is acting in its individual capacity, as opposed to in its capacity as our general partner, it may act without any fiduciary obligation to us or the unitholders whatsoever. These contractual standards replace the obligations to which our general partner would otherwise be held.
	If our general partner does not obtain approval from the conflicts committee of the board of directors of our general partner or our common unitholders, excluding any such units owned by our general partner or its affiliates, and 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, its 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 such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith. These standards replace the obligations to which our general partner would otherwise be held.
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 third party 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.

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.

Under our partnership agreement, we must indemnify our general partner and its officers, directors, managers and certain other specified persons, to the fullest extent permitted by law, against liabilities, costs and expenses incurred by our general partner or these other persons. We must provide this indemnification unless there has been a final and non-appealable judgment by a court of competent jurisdiction determining that such losses or liabilities were the result of conduct of our general partner or such officer or director engaged by it in bad faith, willful misconduct or fraud or, with respect to any criminal conduct, with the knowledge that its conduct was unlawful. Thus, our general partner could be indemnified for its negligent acts if it meets the requirements set forth above. To the extent these provisions purport to include indemnification for liabilities arising under the Securities Act, in the opinion of the SEC, such indemnification is contrary to public policy and, therefore, unenforceable. Please read "The Partnership Agreement—Indemnification."

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 under our partnership agreement. For a description of the relative rights and privileges of holders of our common units to partnership distributions, please read "How We Make Distributions." For a description of the rights and privileges of limited partners under our partnership agreement, including voting rights, please read "The Partnership Agreement."

Transfer Agent and Registrar

Computershare Trust Company, N.A. serves 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 such 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 and approvals 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

Our common units are listed on the NASDAQ Global Select Market under the symbol "VNOM."

THE PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. Our partnership agreement is filed as an exhibit to the registration statement of which this prospectus forms a part and is incorporated by reference into this prospectus. 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 "Conflicts of Interest and 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 February 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 limited to 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.

Although our general partner has the ability to cause us and our subsidiaries to engage in activities other than the business of acquiring and exploiting oil and natural gas properties, our general partner may decline to do so free of any duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. 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 such 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 common units.

Diamondback has the ability to ensure passage of, as well as the ability to ensure the defeat of, any amendment which requires a unit majority by virtue of its % ownership of our common units upon completion of this offering.

In voting their common units, our general partner and its affiliates 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 (including common units deemed owned by our general partner) 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 such units in which case the quorum shall be such greater percentage.

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

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. 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	Under most circumstances, the approval of a majority of the common units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to June 30, 2024 in a manner that would cause a dissolution of our partnership. Please read "—Withdrawal or Removal of Our General Partner."
Removal of our general partner	Not less than 66 2/3% of the outstanding common units, including common units held by our general partner and its affiliates. Please read "—Withdrawal or Removal of Our General Partner."
Transfer of our general partner interest	No approval right. Please read "—Transfer of General Partner Interest."
Transfer of ownership interests in our general partner	No approval right. Please read "—Transfer of Ownership Interests in the General Partner."

If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% 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 our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the units with the specific prior approval of our general partner.

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 such 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 such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such 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, 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 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.

It is likely 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.

Our general partner has the right, which it may from time to time assign in whole or in part to any of its affiliates, to purchase common units, whenever, and on the same terms that, we issue those interests to persons other than our general partner and its affiliates, to the extent necessary to maintain the percentage interest of our general partner and its affiliates, including such interest represented by common units, that existed immediately prior to each issuance. The common unitholders do not have preemptive rights under our partnership agreement to acquire additional common units or other partnership interests.

Amendment of the Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner has no duty or obligation to propose any amendment 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 a manner not adverse to us or the limited partners. 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; or
- 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.

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). Upon completion of the offering, an affiliate of our general partner will own approximately 88.4% of our outstanding common units (approximately 87.8% if the underwriters exercise their option to purchase additional common units in full).

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner 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 or appropriate 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 or appropriate 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, 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 or appropriate 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 or appropriate 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 has 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 such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without such 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 our business is continued, 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.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to June 30, 2024 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after June 30, 2024, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates, other than our general partner and its affiliates. In addition, our partnership agreement permits our general partner, in some instances, to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Interest."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read "—Dissolution."

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66 $^{2}/_{3}$% of the outstanding units, voting together as a single class, including common units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units. The ownership of more than 33 $^{1}/_{3}$% of the outstanding units by our general partner and its affiliates gives them the ability to prevent our general partner's removal. At the closing of this offering, an affiliate of our general partner will own 88.4% of our outstanding common units.

In the event of the removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest of the departing general partner and its affiliates for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner and its affiliates for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partner interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred as a result of the termination of any employees employed for our benefit by the departing general partner or its affiliates.

Transfer of General Partner Interest

At any time, our general partner may transfer all or any of its general partner interest to another person without the approval of our common unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Transfer of Ownership Interests in the General Partner

At any time, the owner of our general partner may sell or transfer all or part of its ownership interests in our general partner to an affiliate or third party without the approval of our unitholders.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Viper Energy Partners GP LLC as our general partner or from otherwise changing our management. Please read "—Withdrawal or Removal of Our General Partner" for a discussion of certain consequences of the removal of our general partner. If any person or group, other than our general partner and its affiliates, acquires beneficial ownership of 20% 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. Please read "—Meetings; Voting."

Limited Call Right

If at any time our general partner and its affiliates own more than 97% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons, as of a record date to be selected by our general partner, on at least 10, but not more than 60, days' notice. If our general partner and its affiliates (including Diamondback) reduce their ownership to below 75% of the outstanding common units, the ownership threshold to exercise the call right will be permanently reduced to 80%. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

- the average of the daily closing prices of the partnership securities of such class over the 20 trading days preceding the date that is three days before the date the notice is mailed.

As a result of our general partner’s right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market. Please read “Material U.S. Federal Income Tax Consequences—Disposition of Units.”

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 such 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 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 such 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 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.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units 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.

Our general partner does not anticipate that any meeting of our unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. 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 has been called, represented in person or by proxy, will constitute a quorum, 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. Our general partner may postpone any meeting of unitholders one or more times for any reason by giving notice to the unitholders entitled to vote at such meeting. Our general partner may also adjourn any meeting of unitholders one or more times for any reason, including the absence of a quorum, without a vote of the unitholders.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Partnership Interests." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates and purchasers specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% 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, calculating required votes, determining the presence of a quorum or for other similar purposes. Common 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.

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

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.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- 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 partners, 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 and its affiliates 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 by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us.

We and our general partner have entered into an advisory services agreement with Wexford pursuant to which Wexford provides general finance and advisory services in exchange for a fee and certain expense reimbursement. Please read “Certain Relationships and Related Party Transactions—Agreements and Transactions with Affiliates.”

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 to his interest as a limited partner, upon reasonable written demand stating the purpose of such 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.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

In addition, we have entered into a registration rights agreement with Diamondback. Pursuant to the registration rights agreement, we are required to file a registration statement to register the common units issued to Diamondback in connection with the IPO. The registration rights agreement also includes provisions dealing with holdback agreements, indemnification and contribution and allocation of expenses. These registration rights are transferable to affiliates of Diamondback and, in certain circumstances, to third parties. Please read "Units Eligible for Future Sale."

UNITS ELIGIBLE FOR FUTURE SALE

Diamondback holds 70,450,000 common units. The sale of these common units could have an adverse impact on the price of the common units or on any trading market that may develop.

Our common units sold in this offering 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. 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 our partnership agreement and the registration rights agreement, our general partner and its 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 partnership agreement and the registration rights agreement, these registration rights allow our general partner and its affiliates or their assignees holding any 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. Our general partner and its affiliates will continue to have these registration rights for two years following its withdrawal or removal as our general partner. 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, our general partner and its 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 and Diamondback have agreed not to sell any common units they beneficially own for a period of 60 days from the date of this prospectus. Please read "Underwriting" for a description of these lock-up provisions.

We filed a registration statement on Form S-8 under the Securities Act to register common units issuable under LTIP. Accordingly, common units issued under the LTIP 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 Viper Energy Partners LP and its subsidiaries.

Legal conclusions contained in this section, unless otherwise noted, are the opinion of Akin Gump Strauss Hauer & Feld LLP 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 Akin Gump Strauss Hauer & Feld LLP 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, Akin Gump Strauss Hauer & Feld LLP 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 such 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 3% 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, Akin Gump Strauss Hauer & Feld LLP is of the opinion that we will be treated as a partnership and our partnership and limited liability company subsidiary will be disregarded as separate from us for federal income tax purposes. The representations made by us and our general partner upon which Akin Gump Strauss Hauer & Feld LLP has relied in rendering its opinion include, without limitation:

(a) Neither we nor any of our partnership or limited liability company subsidiaries 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 IPO, more than 90% of our gross income has been and will be income of a character that Akin Gump Strauss Hauer & Feld LLP 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 Akin Gump Strauss Hauer & Feld LLP 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 such 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, 2017, will be allocated, on a cumulative basis, an amount of federal taxable income that will be approximately 60% 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 such 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 such 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 such 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 the facts and circumstances, including (i) the partner's relative contributions to us, (ii) the interests of all the partners in profits and losses, (iii) the interest of all the partners in cash flow and (iv) the rights of all the partners to distributions of capital upon liquidation. Akin Gump Strauss Hauer & Feld LLP 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 "short seller" to cover a short sale of units) may be treated as having disposed of those units. If so, such 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, Akin Gump Strauss Hauer & Feld LLP 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 Akin Gump Strauss Hauer & Feld LLP 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 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 "—Tax Consequences of Unit Ownership—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 such 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 such 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 such 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, but are not limited to, (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 and commissions 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 such 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, Akin Gump Strauss Hauer & Feld LLP 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 such 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 such 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. Akin Gump Strauss Hauer & Feld LLP 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 such 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 will 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 this offering, we believe our only income is from interest, royalty interests, net profits interests and similar mineral interests and thus we should not have any effectively connected income. We may have effectively connected income in the future if we acquire working interests or otherwise engage, directly or indirectly, in an active trade or business. Furthermore, is it probable that we will be deemed to conduct such 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 their share of our income, gain, loss or deduction and pay federal income tax on their 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 we believe our income from interests, royalty interests, net profits interest and similar mineral interests will not 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. holders 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-8 BEN-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 United States 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 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 such unitholder held the units or the 5-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 Akin Gump Strauss Hauer & Feld LLP 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 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 such 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 such 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 such 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 may be treated as doing business in a number of jurisdictions and many of these jurisdictions impose a personal income tax. 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. Akin Gump Strauss Hauer & Feld LLP 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 VIPER ENERGY PARTNERS LP BY EMPLOYEE BENEFIT PLANS

An investment in us 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, restrictions imposed by Section 4975 of the Internal Revenue Code, and/or provisions under any 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, Keogh plans, 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. 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 plan will satisfy the diversification requirements of Section 404(a)(1)(C) of ERISA and any other applicable Similar Laws; and
- whether the investment will result in recognition of unrelated business taxable income by the 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 us is authorized by the appropriate governing instrument and is a proper investment for the plan.

Section 406 of ERISA and Section 4975 of the Internal Revenue Code prohibit employee benefit plans 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 plan.

In addition to considering whether the purchase of common units is a prohibited transaction, a fiduciary of an employee benefit plan should consider whether the plan will, by investing in us, be deemed to own an undivided interest in our assets, with the result that 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 some circumstances. Under these regulations, an entity's assets 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 widely held by 100 or more investors independent of the issuer and each other, freely transferable and registered under some provisions of the federal securities laws;

(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 less than 25% of the value of each class of equity interest is held by the employee benefit plans referred to above.

Plan fiduciaries contemplating a purchase of common units should consult with their own counsel regarding the consequences under ERISA, the Internal Revenue Code and any other applicable Similar Laws in light of the serious penalties imposed on persons who engage in prohibited transactions or other violations.

UNDERWRITING

Barclays Capital Inc., Credit Suisse Securities (USA) LLC and Wells Fargo Securities, LLC are acting as the representatives of the underwriters and the book-running managers of this offering. Under the terms of an underwriting agreement, which will be filed as an exhibit to the registration statement, 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.	
Credit Suisse Securities (USA) LLC	
Wells Fargo Securities, LLC	
Total	3,500,000

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 and Diamondback 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 discount 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 representatives have 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 such offering price less a selling concession not in excess of $ per common unit. After the offering, the representatives may change the offering price and other selling terms.

The expenses of the offering that are payable by us are estimated to be approximately $ million (excluding underwriting discount). We have also agreed to reimburse the underwriters for certain of their expenses in an amount up to $ as set forth in the underwriting agreement.

Option to Purchase Additional Common Units

We have granted the underwriters an option exercisable for 30 days after the date of this prospectus to purchase, from time to time, in whole or in part, up to an aggregate of 525,000 common units from us at the public offering price less underwriting discounts. This option may be exercised to the extent the underwriters sell more than 3,500,000 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 percentage underwriting commitment in the offering as indicated in the table at the beginning of this section.

Lock-Up Agreements

We, our general partner, Diamondback, the directors and executive officers of our general partner have agreed that, for a period of 60 days after the date of this prospectus, we and they will not directly or indirectly, without the prior written consent of Barclays Capital Inc., (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 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, or sell or grant options, rights or warrants with respect to any common units or securities convertible into or exchangeable for common units, (2) enter into any swap or other derivatives transaction that transfers to another, in whole or in part, any of the economic benefits or risks of ownership of common units, whether any such transaction described in clause (1) or (2) above is to be settled by delivery of common units or other securities, in cash or otherwise, (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, 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. 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.

Indemnification

We and certain of our affiliates have agreed to indemnify the 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 representatives may engage in stabilizing transactions, short sales and purchases to cover positions created by short sales, penalty bids and passive market making 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 representatives to reclaim a selling concession from a syndicate member when the common units originally sold by the syndicate member is purchased in a stabilizing or syndicate covering transaction to cover syndicate short positions.
- In passive market making, market makers in the common units who are underwriters or prospective underwriters may, subject to limitations, make bids for or purchases of our common units until the time, if any, at which a stabilizing bid is made.

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 NASDAQ 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 representatives 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 such allocation for online distributions will be made by the representatives 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.

Listing on the NASDAQ

Our common units are listed on the NASDAQ Global Select Market under the symbol "VNOM."

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.

Other Relationships

The underwriters and certain of their affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. The underwriters and certain of their affiliates have, from time to time, performed, and may in the future perform, various commercial and investment banking and financial advisory services for the issuer and its affiliates, for which they received or may in the future receive customary fees and expenses. We intend to use a portion of the net proceeds of this offering to repay borrowings outstanding under our credit agreement. An affiliate of Wells Fargo Securities, LLC is a lender under the credit agreement and, accordingly, will receive a portion of the net proceeds of this offering.

In the ordinary course of their various business activities, the underwriters and certain of their affiliates may make or hold a broad array of investments 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, and such investment and securities activities may involve securities and/or instruments of the issuer or its affiliates. If the underwriters or their affiliates have a lending relationship with us, the underwriters or their affiliates may hedge their credit exposure to us consistent with their customary risk management policies. Typically, the underwriters and their affiliates would hedge such exposure by entering into transactions which consist of either the purchase of credit default swaps or the creation of short positions in our securities or the securities of our affiliates, including potentially the common units offered hereby. Any such credit default swaps or short positions could adversely affect future trading prices of the common units offered hereby. The underwriters and certain of their affiliates may also communicate independent investment recommendations, market color or trading ideas and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Direct Participation Program Requirements

Because FINRA views the common units offered hereby as interests in a direct participation program, the offering is being made in compliance with FINRA Rule 2310. 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

This prospectus does not constitute an offer to sell to, or a solicitation of an offer to buy from, anyone in any country or jurisdiction (i) in which such an offer or solicitation is not authorized, (ii) in which any person making such offer or solicitation is not qualified to do so or (iii) in which any such offer or solicitation would otherwise be unlawful. No action has been taken that would, or is intended to, permit a public offer of the common units or possession or distribution of this prospectus or any other offering or publicity material relating to the common units in any country or jurisdiction (other than the United States) where any such action for that purpose is required. Accordingly, each underwriter has undertaken that it will not, directly or indirectly, offer or sell any common units or have in its possession, distribute or publish any prospectus, form of application, advertisement or other document or information in any country or jurisdiction except under circumstances that will, to the best of its knowledge and belief, result in compliance with any applicable laws and regulations and all offers and sales of common units by it will be made on the same terms.

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 such 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 such 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:

(a) to any legal entity which is a qualified investor as defined in the Prospectus Directive (“Qualified Investors”);

(b) 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 any such offer; or

(c) 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”) or (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 such 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*).

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 Akin Gump Strauss Hauer & Feld LLP. Certain legal matters in connection with this offering will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas.

EXPERTS

The financial statements of Viper Energy Partners LP as of December 31, 2013 and for the period from inception (September 18, 2013) to December 31, 2013, included in this prospectus and elsewhere in the registration statement, have been so included in reliance upon the report of Grant Thornton LLP, independent registered public accountants, upon the authority of said firm as experts in accounting and auditing.

Information included in this prospectus regarding our estimated quantities of oil and 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 Ryder Scott Company, L.P., an independent 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. The registration statement, including any exhibits and schedules, 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.

We file with or furnish to the SEC periodic reports and other information. These reports and other information may be inspected and copied at the public reference facilities maintained by the SEC or obtained from the SEC's website as provided above. Our website on the Internet is located at http://www.viperenergy.com, and we 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.

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,” “could,” “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 of properties or businesses;
- 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;
- uncertainties with respect to identified drilling locations and estimates of reserves;
- 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. All forward-looking statements speak only as of the date of this prospectus. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this quarterly report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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Viper Energy Partners LP

Consolidated Balance Sheets
(Unaudited)

	June 30, 2014	December 31, 2013*
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash	$ 7,029	$ 762
Royalty income receivable	7,168	9,426
Other current assets	16	—
Total current assets	14,213	10,188
Oil and natural gas interests, based on the full cost method of accounting ($135,642 and $160,302 excluded from depletion at June 30, 2014 and December 31, 2013, respectively)	453,309	448,034
Accumulated depletion	(16,830)	(5,199)
	436,479	442,835
Total assets	$ 450,692	$ 453,023
Liabilities and Unitholders' Equity/Members' Equity		
Current liabilities:		
Accounts payable	$ 720	$ —
Accounts payable—related party	607	9,779
Other accrued liabilities	1,434	256
Distribution payable—related party	11,260	—
Total current liabilities	14,021	10,035
Note payable—related party	—	440,000
Total liabilities	14,021	450,035
Commitments and contingencies (Note 11)		
Members' equity	—	2,988
Unitholders' equity:		
General partner	—	—
Common units (76,200,000 units issued and outstanding as of June 30, 2014)	436,671	—
Total unitholders' equity	436,671	2,988
Total liabilities and unitholders' equity/members' equity	$ 450,692	$ 453,023

See accompanying notes to consolidated financial statements.
* See Note 1 for information regarding the basis of financial statement presentation.

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Viper Energy Partners LP

Consolidated Statements of Operations
(Unaudited)

	Three Months Ended June 30, 2014*	Six Months Ended June 30, 2014*	Period From Inception (September 18, 2013) Through December 31, 2013*
	(In thousands, except per unit amounts)		
Royalty income	$17,249	$33,102	$ 14,987
Expenditures:			
Production and ad valorem taxes	1,392	2,313	972
Depletion	6,064	11,631	5,199
General and administrative expenses	219	285	—
General and administrative expenses—related party	78	156	87
Interest expense—related party, net of capitalized interest	5,387	10,755	5,741
Total expenditures	13,140	25,140	11,999
Net income	$ 4,109	$ 7,962	$ 2,988
Allocation of net income:			
Net income attributable to the period through June 22, 2014	$ 3,168	$ 7,021	
Net income attributable to the period June 23, 2014 through June 30, 2014	941	941	
	$ 4,109	$ 7,962	
Net income attributable to common limited partners per unit:			
Basic and diluted	$ 0.01	$ 0.01	
Weighted average number of limited partner units outstanding			
Basic and diluted	76,200	76,200	

See accompanying notes to consolidated financial statements.
* See Note 1 for information regarding the basis of financial statement presentation.

Viper Energy Partners LP

Statement of Consolidated Unitholders' Equity and Members' Equity
(Unaudited)

	Limited Partners Common	Predecessor Members' Equity	Total
		(In thousands)	
Balance at December 31, 2013*	$ —	$ 2,988	$ 2,988
Net income attributable to the period through June 22, 2014	—	7,021	7,021
Contribution of Note Payable to Equity	—	437,115	437,115
Distribution payable to Diamondback (Note 1)	—	(11,260)	(11,260)
Exchange of Predecessor interests for units (Note 1)	435,864	(435,864)	—
Net proceeds from the issuance of common units	137,238	—	137,238
Distribution to Diamondback (Note 1)	(137,500)	—	(137,500)
Unit-based compensation	128	—	128
Net income attributable to the period June 23, 2014 through June 30, 2014	941	—	941
Balance at June 30, 2014	$ 436,671	$ —	$ 436,671

See accompanying notes to consolidated financial statements.
* See Note 1 for information regarding the basis of financial statement presentation.

Viper Energy Partners LP

Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30, 2014*	Period From Inception (September 18, 2013) Through December 31, 2013*
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 7,962	$ 2,988
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion	11,631	5,199
Unit-based compensation expense	128	—
Changes in operating assets and liabilities:		
Royalty income receivable	2,258	(9,426)
Other current assets	(16)	—
Accounts payable—related party	(9,172)	5,828
Accounts payable and other accrued liabilities	1,273	256
Net cash provided by operating activities	14,064	4,845
Cash flows from investing activities:		
Additions to oil and natural gas interests	(5,275)	(4,083)
Net cash used in investing activities	(5,275)	(4,083)
Cash flows from financing activities		
Principal payment on subordinated note	(2,885)	—
Proceeds from initial public offering	139,035	—
Initial public offering costs	(1,172)	—
Distribution to Diamondback (Note 1)	(137,500)	—
Net cash used in financing activities	(2,522)	—
Net increase in cash	6,267	762
Cash at beginning of period	762	—
Cash at end of period	$ 7,029	$ 762
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$ 16,496	$ —
Supplemental disclosure of non-cash transactions:		
Mineral interest acquired in exchange for note payable	$ —	$ 440,000
Note payable converted to equity	$ 437,115	$ —
Capitalized interest	$ 5,275	$ 3,951

See accompanying notes to consolidated financial statements.
* See Note 1 for information regarding the basis of financial statement presentation.

Viper Energy Partners LP

Notes to Financial Statements
(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Viper Energy Partners LP (the "Partnership") is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol "VNOM". The Partnership was formed by Diamondback Energy, Inc., a Delaware corporation (together with its subsidiaries, "Diamondback"), on February 27, 2014 to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin. Unless the context requires otherwise, references to "we," "us," "our," or "the Partnership" are intended to mean the business and operations of Viper Energy Partners LP and its consolidated subsidiary, Viper Energy Partners LLC (the "Predecessor"), a Delaware limited liability company.

Prior to the completion on June 23, 2014 of the Partnership's initial public offering (the "IPO") of 5,750,000 common units representing limited partner interests, Diamondback owned all of the general and limited partner interests in the Partnership. On June 23, 2014, the Partnership completed its IPO of 5,750,000 common units representing limited partner interests at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. We received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the IPO, Diamondback contributed all of the membership interests in the Predecessor to the Partnership in exchange for 70,450,000 common units, and Viper Energy Partners GP LLC (the "General Partner"), a Delaware limited liability company, maintained its non-economic general partner interest. In addition, in connection with the closing of the IPO, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.3 million and the net proceeds from the IPO. As of June 30, 2014, the Partnership had distributed $137.5 million to Diamondback and the Partnership recorded a payable balance of approximately $11.3 million.

The contribution of the Predecessor to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

As of June 30, 2014, the General Partner held a 100% non-economic general partner interest in the Partnership, and our affiliates had an approximate 93% limited partner interest in the Partnership consisting of Diamondback holding an approximate 92% limited partner interest and Wexford Capital LP ("Wexford") holding an approximate 1% limited partner interest. Diamondback owns and controls the General Partner.

Basis of Presentation

The consolidated results of operations following the completion of the IPO are presented together with the results of operations pertaining to our Predecessor. The assets of the Predecessor consisted of mineral interests in oil and natural gas properties in the Permian Basin, which were acquired on September 19, 2013. See Note 3—Acquisition. The contribution of the Predecessor to the Partnership on June 17, 2014 was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. The Partnership did not own any assets prior to June 17, 2014, the date of the contribution agreement by and among Diamondback, the Predecessor, the General Partner and the Partnership. Prior to the IPO, the Predecessor was a wholly owned subsidiary of Diamondback. For periods prior to June 17, 2014, the accompanying consolidated financial statements and related notes thereto represent the financial position, results of operations, cash flows and changes in members' equity of the Predecessor and, for periods on and after June 17, 2014, the accompanying consolidated financial statements and related notes thereto represent the financial position, results of operations, cash flows and changes in partners' equity of the Partnership and its wholly owned subsidiary.

The accompanying consolidated financial statements and related notes thereto were prepared in conformity with accounting principles that are generally accepted in the United States. All material intercompany balances and transactions are eliminated in consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Partnership's financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities at the date of the financial statements.

We evaluate these estimates on an ongoing basis, using historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Partnership's estimates. Any effects on the Partnership's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties and unit–based compensation.

Royalty Income Receivable

Royalty income receivable consist of receivables from oil and natural gas sales delivered to purchasers. Those purchasers remit payment for production to the operator of the properties and the operator, in turn, remits payment to us. Some of our oil and natural gas properties are contractually operated by Diamondback. Most payments are received within three months after the production date.

Royalty income receivable are stated at amounts due from operators, net of an allowance for doubtful accounts when we believe collection is doubtful. Royalty income receivable outstanding longer than the contractual payment terms are considered past due. We determine any allowance by considering a number of factors, including the length of time royalty income receivable are past due, our previous loss history, the debtor's current ability to pay its obligation to us, the condition of the general economy and the industry as a whole. We write off specific royalty income receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. We determined that an allowance was unnecessary at both June 30, 2014 and December 31, 2013.

Fair Value of Financial Instruments

Our financial instruments consist of cash, receivables, payables and a note payable. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of the instruments. The note payable is carried at cost, which approximates fair value based on borrowing rates available to us for bank loans with similar terms and maturities.

Viper Energy Partners LP

Notes to Financial Statements
(Unaudited)

Oil and Natural Gas Properties

Oil and natural gas producing activities are accounted for in accordance with the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. At June 30, 2014 and December 31, 2013, the Partnership's oil and natural gas properties consist solely of mineral interests in oil and natural gas properties.

Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $27.44, $27.95 and $27.53 for the three months and six months ended June 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013, respectively. Depletion for oil and gas properties was $6,064,000, $11,631,000 and $5,199,000 for the three months and six months ended June 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013, respectively.

Under the full cost method of accounting, the net book value of oil and natural gas properties, may not exceed a calculated "ceiling". The ceiling limitation is the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%. Estimated future net cash flows are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production. Any excess of the net book value of proved oil and natural gas properties over the ceiling is charged to expense. No impairment on proved oil and natural gas properties was recorded for the three months and six months ended June 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property on an annual basis for possible impairment. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Capitalized Interest

We capitalize interest on expenditures made in connection with acquisitions of unproved properties that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these properties to their intended use. Capitalized interest cannot exceed gross interest expense. During the three months and six months ended June 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013, we capitalized approximately $2,348,000, $5,275,000 and $3,951,000, respectively, of interest expense.

Royalty Interest and Revenue Recognition

Royalty interest represents the right to receive revenues (oil and natural gas sales), less production and operating taxes and post-production costs. Revenue is recorded when title passes to the purchaser.

Viper Energy Partners LP

Notes to Financial Statements
(Unaudited)

Royalty interest has no rights or obligations to explore, develop or operate the property and does not incur any of the costs of exploration, development and operation of the property.

Concentrations

We are subject to risk resulting from the concentration of our royalty interest revenues in producing oil and natural gas properties and receivables with several significant purchasers. For the six months ended June 30, 2014, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (70%); and Permian Transport & Trading (12%). For the period from inception (September 18, 2013) to December 31, 2013, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (59%); and Permian Transport & Trading (19%). We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Earnings Per Unit

Earnings per unit applicable to limited partners is computed by dividing limited partners' interest in net income by the weighted average number of outstanding common units.

Unit–Based Compensation

Unit–based compensation awards are measured at fair value on the date of grant and are expensed, net of estimated forfeitures, over the required service period. See Note 8—Unit–Based Compensation.

Income Taxes

The Partnership is organized as a pass-through entity for income tax purposes. As a result, our partners are responsible for federal income taxes on their share of our taxable income.

We are subject to the Texas margin tax. Any amounts related to operations for 2013 or for the period in 2014 prior to the closing of the IPO on June 23, 2014 will be included in Diamondback's unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for the six months ended June 30, 2014 or the period from inception (September 18, 2013) through December 31, 2013, so no amount has been provided in the accompanying financial statements of our Predecessor.

3. ACQUISITION

On September 19, 2013, Diamondback completed the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin for $440 million. As part of the closing of the acquisition, the mineral interests were conveyed from the previous owners to the Predecessor. The mineral interests entitle us to receive an average 21.4% royalty interest on all production from this acreage with no additional future capital or operating expense required. The acquisition was accounted for as an acquisition of assets.

Viper Energy Partners LP

Notes to Financial Statements
(Unaudited)

4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	June 30, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$317,667	$ 287,732
Not subject to depletion—acquisition costs		
Incurred in 2014	5,275	—
Incurred in 2013	130,367	160,302
Total not subject to depletion	135,642	160,302
Gross oil and natural gas interests	453,309	448,034
Less accumulated depletion	(16,830)	(5,199)
Oil and natural gas interests, net	$436,479	$ 442,835

Costs associated with unevaluated properties are excluded from the full cost pool until a determination as to the existence of proved reserves is able to be made. The inclusion of our unevaluated costs into the amortization base is expected to be completed within three to five years.

5. DEBT

Credit Facility-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo Bank, National Association, or Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of July 8, 2014, the borrowing base was set at $110.0 million, and Wells Fargo was the only lender under the credit agreement, with a maximum credit amount of $55.0 million. Under the credit agreement, the commitment of the lenders is equal to the lessor of the aggregate maximum credit amounts of the lenders and the borrowing base. As of August 6, 2014, the borrowing base and the commitment were $110.0 million with Wells Fargo as the only lender under the credit agreement. The Partnership had outstanding borrowings of $68.0 million as of August 12, 2014.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Partnership that is based on the prime rate or LIBOR plus margins ranging from 0.50% for prime-based loans and 1.50% for LIBOR loans to 1.50% for prime-based loans and 2.50% for LIBOR loans, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Partnership is 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 loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount 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 of July 8, 2019. The loan is secured by substantially all of the assets of the Partnership and its subsidiaries.

Viper Energy Partners LP

Notes to Financial Statements
(Unaudited)

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

EBITDAX will be annualized beginning with the quarter ending September 30, 2014 and ending with the quarter ended March 31, 2015

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

The lenders may accelerate all of the indebtedness under the Partnership's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

Subordinated Note

Effective September 19, 2013, the Predecessor issued a subordinated note to Diamondback for the principal sum of $440.0 million for the royalty interest acquisition discussed in Note 3. In connection with the IPO, the subordinated note was converted to equity. The note bore interest at 7.625% per annum. Interest was due and payable monthly in arrears on the first business day of each calendar month. The unpaid principal balance and all accrued interest on the note were due and payable in full on October 1, 2021. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under the Diamondback revolving credit facility. Prior to the completion of the IPO, there was $437.1 million of principal and interest outstanding under this note. We owed $9.7 million of accrued interest as of December 31, 2013, which is included in accounts payable—related party in the accompanying balance sheets.

6. FAIR VALUE MEASUREMENTS

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. Our assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. We use appropriate valuation techniques based on available inputs to measure the fair values of our assets and liabilities.

Level 1—Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Viper Energy Partners LP

Notes to Financial Statements
(Unaudited)

Level 2—Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3—Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

On July 8, 2014, we entered into a secured revolving credit agreement. See Note 5—Debt. The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

7. RELATED PARTY TRANSACTIONS

Partnership agreement

In connection with the closing of the IPO, the General Partner and Diamondback entered into the first amended and restated agreement of limited partnership (the "Partnership Agreement"), dated June 23, 2014.

The Partnership Agreement requires us to reimburse the General Partner for all direct and indirect expenses incurred or paid on our behalf and all other expenses allocable to us or otherwise incurred by our General Partner in connection with operating our business. The Partnership Agreement does not set a limit on the amount of expenses for which our General Partner and its affiliates 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 by its affiliates. Our General Partner is entitled to determine the expenses that are allocable to us.

Advisory Services Agreement

In connection with the closing of the IPO, the Partnership and General Partner entered into an advisory services agreement (the "Advisory Services Agreement") with Wexford, dated as of June 23, 2014, under which Wexford provides us and our General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Advisory Services Agreement has a term of two years commencing on June 23, 2014, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event we terminate such agreement, we are obligated to pay all amounts due through the remaining term. In addition, we have agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of our General Partner for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions in which we may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to our day-to-day business or operations. We have agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct.

Viper Energy Partners LP

Notes to Financial Statements
(Unaudited)

Tax Sharing

In connection with the closing of the IPO, the Partnership entered into a tax sharing agreement (the “Tax Sharing Agreement”) with Diamondback pursuant to which we will reimburse Diamondback for our share of state and local income and other taxes for which our results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax the Partnership would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which we may be a member for this purpose, to owe less or no tax. In such a situation, we would reimburse Diamondback for the tax we would have owed had the tax attributes not been available or used for our benefit, even though Diamondback had no cash tax expense for that period.

Shared service agreements

Effective September 19, 2013, the Predecessor entered into a shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback Energy, Inc. This agreement was terminated in connection with the IPO. Under this agreement, Diamondback E&P LLC provided consulting and administrative services to the Predecessor. The Predecessor incurred a monthly charge for the services of $26,000. For the three months and six months ended June 30, 2014 and for the period from inception (September 18, 2013) to December 31, 2013, we incurred costs of $78,000, $156,000 and $87,000, respectively. At June 30, 2014 and December 31, 2013, the Partnership owed Diamondback E&P LLC $607,000 and $87,000, respectively, which amounts are included in accounts payable—related party in the accompanying balance sheets.

8. UNIT–BASED COMPENSATION

On June 17, 2014, in connection with the IPO, the Board of Directors of the General Partner adopted the Viper Energy Partners LP Long Term Incentive Plan (“LTIP”), effective June 17, 2014, for employees, officers, consultants and directors of the General Partner and any of its affiliates, including Diamondback, who perform services for the Partnership. The LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards. A total of 9,144,000 common units has been reserved for issuance pursuant to the LTIP. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The LTIP is administered by the Board of Directors of the General Partner or a committee thereof.

For the three months and six months ended June 30, 2014, we incurred $128,000 and $128,000, respectively of unit–based compensation.

Unit Options

In accordance with the LTIP, the exercise price of unit options granted may not be less than the market value of the common units at the date of grant. The units issued under the LTIP will consist of new common units of the Partnership. On June 17, 2014, we granted 2,500,000 unit options to our executive officers of the General Partner. The unit options vest approximately 33% ratably on each of the next three anniversaries of the date of grant. In the event the fair market value per unit as of the exercise date is less than the exercise price per option unit then the vested options will automatically terminate and become null and void as of the exercise date.

The fair value of the unit options on the date of grant is expensed over the applicable vesting period. We estimate the fair values of unit options granted using a Black-Scholes option valuation model, which requires us to make several assumptions. At the time of grant we did not have a history of market prices, thus the expected

Viper Energy Partners LP

Notes to Financial Statements
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volatility was determined using the historical volatility for a peer group of companies. The expected term of options granted was determined based on the contractual term of the awards. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the unit option at the date of grant. The expected dividend yield was based upon projected performance of the Partnership.

	2014
Grant-date fair value	$4.24
Expected volatility	36.0%
Expected dividend yield	5.9%
Expected term (in years)	3.0
Risk-free rate	0.99%

The following table presents the unit option activity under the LTIP for the six months ended June 30, 2014:

	Unit Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	—	$ —		
Granted	2,500,000	$26.00		
Outstanding at June 30, 2014	2,500,000	$26.00	2.97	$ 19,500
Vested and Expected to vest at June 30, 2014	2,500,000	$26.00	2.97	$ 19,500
Exercisable at June 30, 2014	—	$ —	—	$ —

As of June 30, 2014, the unrecognized compensation cost related to unvested unit options was $10,472,000. Such cost is expected to be recognized over a weighted-average period of 3.0 years.

9. UNITHOLDERS’ EQUITY AND PARTNERSHIP DISTRIBUTIONS

The Partnership has general partner and common unit partnership interests. The general partner interest is a non-economic interest and is not entitled to any cash distributions.

At June 30, 2014, the Partnership had a total of 76,200,000 common units issued and outstanding, of which 70,450,000 common units were owned by Diamondback, representing approximately 92% of the total Partnership units outstanding.

The board of directors of our General Partner has adopted a policy for the Partnership to distribute all available cash generated on a quarterly basis, beginning with the quarter ending September 30, 2014. Our first distribution, however, will include available cash for the period from June 23, 2014, the date of the close of the IPO, through September 30, 2014. Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of the General Partner following the end of such quarter. Available cash for each quarter will generally equal Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors of our General Partner deems necessary or appropriate, if any.

Viper Energy Partners LP

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(Unaudited)

10. EARNINGS PER UNIT

The net income per common unit on the consolidated statements of operations is based on the net income of the Partnership after the closing of its IPO on June 23, 2014 through June 30, 2014, since this is the amount of net income that is attributable to the Partnership's common units.

The Partnership's net income is allocated wholly to the common units as the General Partner does not have an economic interest.

Basic and diluted net income per common unit is calculated by dividing net income by the weighted-average number of common units outstanding during the period.

	June 23, 2014 to June 30, 2014
Net income attributable to the period June 23, 2014 through June 30, 2014	$ 941,000
Net income per common unit, basic	$ 0.01
Net income per common unit, diluted	$ 0.01
Weighted-average common units outstanding, basic	76,200,000
Weighted-average common units outstanding, diluted	76,200,000

11. COMMITMENTS AND CONTINGENCIES

We could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

12. SUBSEQUENT EVENTS

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. See Note 5—Debt for further information.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors
Viper Energy Partners GP LLC

We have audited the accompanying balance sheet of Viper Energy Partners LP (a Delaware limited partnership) (the “Partnership”) as of December 31, 2013, and the related statements of operations, members’ equity, and cash flows for the period from inception (September 18, 2013) through December 31, 2013. These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on these financial statements 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 financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership’s 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 financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Viper Energy Partners LP as of December 31, 2013, and the results of its operations and its cash flows for the period from inception (September 18, 2013) through December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
August 13, 2014

Viper Energy Partners LP

Balance Sheet
December 31, 2013
(In thousands)

Assets	
Current assets:	
Cash	$ 762
Royalty income receivable	9,426
Total current assets	10,188
Oil and natural gas interests, based on the full cost method of accounting ($160,302 excluded from depletion at December 31, 2013)	448,034
Accumulated depletion	(5,199)
	442,835
Total assets	$453,023
Liabilities and Members' Equity	
Current liabilities:	
Accounts payable—related party	$ 9,779
Other accrued liabilities	256
Total current liabilities	10,035
Note payable—related party	440,000
Total liabilities	450,035
Commitments and contingencies (Note 7)	
Members' equity	2,988
Total liabilities and members' equity	$453,023

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

Viper Energy Partners LP

Statement of Operations

Period From Inception (September 18, 2013) Through December 31, 2013
(In thousands)

Royalty income	$14,987
Expenditures:	
Production and ad valorem taxes	972
Depletion	5,199
General and administrative expenses—related party	87
Interest expense—related party, net of capitalized interest	5,741
Total expenditures	11,999
Net income	$ 2,988

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

Viper Energy Partners LP

Statement of Members' Equity

Period From Inception (September 18, 2013) Through December 31, 2013
(In thousands)

Balance at inception (September 18, 2013)	$ —
Net income	2,988
Balance at December 31, 2013	$2,988

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

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Viper Energy Partners LP

Statement of Cash Flows

Period From Inception (September 18, 2013) Through December 31, 2013
(In thousands)

Cash flows from operating activities:	
Net income	$ 2,988
Adjustments to reconcile net income to net cash provided by operating activities:	
Depletion	5,199
Changes in operating assets and liabilities:	
Accounts receivable	(9,426)
Accounts payable-related party	5,828
Accrued liabilities	256
Net cash provided by operating activities	4,845
Cash flows from investing activities:	
Additions to oil and natural gas interests	(4,083)
Net cash used in investing activities	(4,083)
Net increase in cash	762
Cash at beginning of period	—
Cash at end of period	$ 762
Supplemental disclosure of non-cash transactions:	
Mineral interest acquired in exchange for note payable	$440,000
Capitalized interest	$ 3,951

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

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Viper Energy Partners LP (the "Partnership") is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol "VNOM". The Partnership was formed by Diamondback Energy, Inc., a Delaware corporation (together with its subsidiaries, "Diamondback"), on February 27, 2014 to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin. Unless the context requires otherwise, references to "we," "us," "our," or "the Partnership" are intended to mean the business and operations of Viper Energy Partners LP and its consolidated subsidiary, Viper Energy Partners LLC (the "Predecessor"), a Delaware limited liability company.

The Predecessor was formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The assets of the Predecessor consisted of mineral interests in oil and natural gas properties in the Permian Basin, which were acquired on September 19, 2013. See Note 3—Acquisition. For the period from its inception to June 17, 2014, the Predecessor was a wholly owned subsidiary of Diamondback.

Prior to the completion on June 23, 2014 of the Partnership's initial public offering (the "IPO") of 5,750,000 common units representing limited partner interests, Diamondback owned all of the general and limited partner interests in the Partnership. On June 23, 2014, the Partnership completed its IPO of 5,750,000 common units representing limited partner interests, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms.

In connection with the IPO, on June 17, 2014, Diamondback contributed all of the membership interests in the Predecessor to the Partnership in exchange for 70,450,000 common units, and Viper Energy Partners GP LLC (the "General Partner"), a Delaware limited liability company, maintained its non-economic general partner interest.

Basis of Presentation

The contribution of the Predecessor to the Partnership on June 17, 2014 was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests and with the operations of the Partnership and the Predecessor as if they were consolidated for all periods presented. The Partnership did not own any assets prior to June 17, 2014, the date of the contribution agreement by and among Diamondback, the Predecessor, the General Partner and the Partnership. Therefore, the accompanying consolidated financial statements and related notes thereto represent the financial position, results of operations, cash flows and changes in members' equity of the Predecessor.

The accompanying consolidated financial statements and related notes thereto were prepared in conformity with accounting principles that are generally accepted in the United States.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Partnership's financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts the Partnership reports for assets and liabilities and the Partnership's disclosure of contingent assets and liabilities at the date of the financial statements.

The Partnership evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Partnership considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Partnership's estimates. Any effects on the Partnership's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom and the carrying value of oil and natural gas properties.

Accounts Receivable

Accounts receivable consist of receivables from oil and natural gas sales delivered to purchasers. Those purchasers remit payment for production to the operator of the properties and the operator, in turn, remits payment to the Partnership. Some of the Partnership's oil and natural gas properties are contractually operated by Diamondback. Most payments are received within three months after the production date.

Accounts receivable are stated at amounts due from operators, net of an allowance for doubtful accounts when the Partnership believes collection is doubtful. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Partnership determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Partnership's previous loss history, the debtor's current ability to pay its obligation to the Partnership, the condition of the general economy and the industry as a whole. The Partnership writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2013.

Fair Value of Financial Instruments

The Partnership's financial instruments consist of cash, receivables, payables and a note payable. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of the instruments. The note payable is carried at cost, which approximates fair value based on borrowing rates available to the Partnership for bank loans with similar terms and maturities.

Oil and Natural Gas Properties

The Partnership accounts for its oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. At December 31, 2013, the Partnership's oil and natural gas properties consist solely of mineral interests in oil and natural gas properties.

Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $27.53 for the period from inception (September 18, 2013) to December 31, 2013. Depletion for oil and gas properties was $5.2 million for the same period.

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

Under the full cost method of accounting, the net book value of oil and natural gas properties, may not exceed a calculated "ceiling". The ceiling limitation is the estimated future net cash flows from proved oil and natural gas reserves, discounted at 10%. Estimated future net cash flows are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production. Any excess of the net book value of proved oil and natural gas properties over the ceiling is charged to expense. No impairment on proved oil and natural gas properties was recorded for the period from inception (September 18, 2013) through December 31, 2013.

Costs associated with unevaluated properties are excluded from the full cost pool until the Partnership has made a determination as to the existence of proved reserves. The Partnership assesses all items classified as unevaluated property on an annual basis for possible impairment. The Partnership assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Capitalized Interest

The Partnership capitalizes interest on expenditures made in connection with acquisitions of unproved properties that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these properties to their intended use. Capitalized interest cannot exceed gross interest expense. During the period from inception (September 18, 2013) to December 31, 2013, the Partnership capitalized approximately $4.0 million of interest expense.

Royalty Interest and Revenue Recognition

Royalty interest represents the right to receive revenues (oil and natural gas sales), less production and operating taxes and post-production costs. Revenue is recorded when title passes to the purchaser.

Royalty interest has no rights or obligations to explore, develop or operate the property and does not incur any of the costs of exploration, development and operation of the property.

Concentrations

The Partnership is subject to risk resulting from the concentration of its royalty interest revenues in producing oil and natural gas properties and receivables with several significant purchasers. For the period from inception (September 18, 2013) to December 31, 2013, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (59%); and Permian Trucking (19%). The Partnership does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Income Taxes

The Partnership and the Predecessor are organized as pass-through entities for income tax purposes. Prior to the IPO, as appropriate, the taxable income or loss applicable to operations of the Predecessor was included in the federal income tax returns of Diamondback Energy, Inc. and no income tax effect is included in the accompanying financial statements.

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

The Partnership is subject to the Texas margin tax. Any amounts related to the Partnership for 2013 will be included in Diamondback's unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for 2013, so no amount has been provided in these financial statements. On a stand-alone basis, the Partnership would have owed approximately $98 for the Texas margin tax in 2013.

3. ACQUISITION

On September 19, 2013, Diamondback completed the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin for $440 million. As part of the closing of the acquisition the mineral interests were conveyed from the previous owners to the Partnership. The mineral interests entitle the Partnership to receive an average 21.4% royalty interest on all production from this acreage with no additional future capital or operating expense required. The acquisition was accounted for as an acquisition of assets.

4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	December 31, 2013
Oil and natural gas interests:	
Subject to depletion	$ 287,732
Not subject to depletion-acquisition costs	
Incurred in 2013	160,302
Total not subject to depletion	160,302
Gross oil and natural gas interests	448,034
Less accumulated depletion	(5,199)
Oil and natural gas interests, net	$ 442,835

Costs associated with unevaluated properties are excluded from the full cost pool until the Partnership has made a determination as to the existence of proved reserves. The inclusion of the Partnership's unevaluated costs into the amortization base is expected to be completed within three to five years.

5. NOTE PAYABLE

Subordinated Note

Effective September 19, 2013 the Partnership issued a subordinated note to Diamondback for the principal sum of $440 million for the royalty interest acquisition discussed in Note 3. The note bears interest at 7.625% per annum. Interest is due and payable monthly in arrears on the first business day of each calendar month. The unpaid principal balance and all accrued interest on the note are due and payable in full on October 1, 2021. Any indebtedness evidenced by this note is subordinate in the right of payment to any indebtedness outstanding under the Diamondback revolving credit facility. As of December 31, 2013 there was $440 million outstanding under this note and the Partnership owed $9.7 million of accrued interest which is included in accounts payable-related party in the accompanying balance sheet.

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

6. RELATED PARTY TRANSACTIONS

Effective September 19, 2013 the Partnership entered into a shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback Energy, Inc. Under this agreement, Diamondback E&P LLC, provides consulting and administrative services to the Partnership. The Partnership will incur a monthly charge for the services of $26 or other amounts that are otherwise mutually agreed to in writing between Diamondback E&P LLC and the Partnership. The term of the shared services agreement continues from the effective date on a month-to-month basis until cancelled by either party upon thirty days written notice. For the period from inception (September 18, 2013) to December 31, 2013 the Partnership incurred $87 for services under this agreement. At December 31, 2013 the Partnership owed Diamondback E&P LLC $87 and this amount is included in accounts payable-related party in the accompanying balance sheet.

At December 31, 2013, the Partnership's oil and natural gas properties consist solely of mineral interests in oil and natural gas properties. These interests are subject to oil and gas leases between the Partnership as lessor and Diamondback O&G LLC as lessee and are pledged as collateral to secure the Diamondback Energy, Inc. revolving credit facility.

7. COMMITMENTS AND CONTINGENCIES

The Partnership could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

8. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Partnership's oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion and amortization are as follows:

	December 31, 2013
Oil and natural gas interests:	
Proved	$ 287,732
Unproved	160,302
Total oil and natural gas interests	448,034
Less accumulated depletion	(5,199)
Net oil and natural gas interests capitalized	$ 442,835

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

Costs incurred in oil and natural gas activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows:

	Period From Inception (September 18, 2013) Through December 31, 2013
Acquisition costs	
Proved	$ 200,309
Unproved	247,725
Total	$ 448,034

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and natural gas. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to the net operating results of our oil, natural gas and natural gas liquids operations.

	Period From Inception (September 18, 2013) Through December 31, 2013
Royalty income	$ 14,987
Production and ad valorem taxes	(972)
Depletion	(5,199)
Results of operations from oil, natural gas and natural gas liquids	$ 8,816

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2013 were prepared by Ryder Scott Company, L.P., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

The changes in estimated proved reserves are as follows:

	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves:			
Balance at inception (September 18, 2013)	—	—	—
Purchase of reserves in place	5,725,640	1,672,824	7,418,633
Extensions and discoveries	1,724,366	364,047	2,403,261
Revisions of previous estimates	(81,111)	(841,777)	1,547,955
Production	(150,815)	(19,971)	(108,264)
As of December 31, 2013	7,218,080	1,175,123	11,261,585
Proved Developed Reserves:			
December 31, 2013	3,692,207	609,303	6,280,409
Proved Undeveloped Reserves:			
December 31, 2013	3,525,873	565,820	4,981,176

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is based on the unweighted average, first-day-of-the-month price. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Partnership. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Partnership's proved oil and natural gas reserves as of December 31, 2013.

	December 31, 2013
Future cash inflows	$ 770,528
Future production taxes	(53,040)
Future state margin tax expenses	(5,394)
Future net cash flows	712,094
10% discount to reflect timing of cash flows	(384,848)
Standardized measure of discounted future net cash flows	$ 327,246

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

In the table below the average first-day-of–the-month price for oil, natural gas and natural gas liquids is presented, all utilized in the computation of future cash inflows.

	December 31, 2013 Unweighted Arithmetic Average First-Day-of-the-Month Prices
Oil (per Bbl)	$ 92.64
Natural gas (per Mcf)	$ 5.03
Natural gas liquids (per Bbl)	$ 38.45

Principal changes in the standardized measure of discounted future net cash flows attributable to the Partnership's proved reserves are as follows:

	Period From Inception (September 18, 2013) Through December 31, 2013
Standardized measure of discounted future net cash flows at the beginning of the period	$ —
Purchase of minerals in place	249,831
Sales of oil and natural gas, net of production costs	(14,015)
Extensions and discoveries	79,829
Net changes in prices and production costs	24,724
Revisions of previous quantity estimates	(19,383)
Net changes in state margin taxes	(586)
Accretion of discount	7,103
Net changes in timing of production and other	(257)
Standardized measure of discounted future net cash flows at the end of the period	$ 327,246

9. SUBSEQUENT EVENTS

IPO and Subordinated Note

On June 23, 2014, the Partnership completed its IPO. See Note 1—Organization and Basis of Presentation for further information. In connection with the IPO, the subordinated note discussed in Note 5—Note Payable was converted to equity.

Credit Facility-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo Bank, National Association, or Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may

Viper Energy Partners LP

Notes to Financial Statements
(Amounts in thousands, unless otherwise noted)

request up to three additional redeterminations of the borrowing base during any 12-month period. As of July 8, 2014, the borrowing base was set at $110.0 million, and Wells Fargo was the only lender under the credit agreement, with a maximum credit amount of $55.0 million. Under the credit agreement, the commitment of the lenders is equal to the lessor of the aggregate maximum credit amounts of the lenders and the borrowing base. As of August 6, 2014, the borrowing base was increased to $110.0 million with Wells Fargo as the only lender under the credit agreement. The Partnership had outstanding borrowings of $50.0 million as of August 6, 2014.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Partnership that is 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 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Partnership is 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 loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount 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 of July 8, 2019. The loan is secured by substantially all of the assets of the Partnership and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

EBITDAX will be annualized beginning with the quarter ending September 30, 2014 and ending with the quarter ended March 31, 2015

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

The lenders may accelerate all of the indebtedness under the Partnership's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

Appendix A

GLOSSARY OF TERMS

The following are definitions of certain terms used in this prospectus.

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Basin. A large depression on the earth's surface in which sediments accumulate.

Bbl. Stock tank barrel, or 42 U.S. gallons liquid volume, used in this prospectus in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Bbls per day.

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. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilled 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. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

Crude oil. Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.

Delaware Act. Delaware Revised Uniform Limited Partnership Act.

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 a natural gas or oil 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 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.

Estimated Ultimate Recovery or EUR. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploitation. A development 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 prospects. 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.

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.

Finding and 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.

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 with a specified interval.

Horizontal wells. Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.

MBbls. 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, condensate or natural gas liquids.

Mcf. Thousand cubic feet of natural gas.

Mcf/d. Mcf per day.

Mineral interests. The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.

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 and overriding interests.

NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX. New York Mercantile Exchange.

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.

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.

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.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves. The estimated quantities of oil, natural gas and natural gas liquids 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.

Recompletion. The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

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.

Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) 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 very low flow rates for long periods of time.

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.

Wellbore. The hole drilled by the bit that is equipped for oil or natural gas production on a completed well.

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.

WTI. West Texas Intermediate.

Viper Energy Partners LP

3,500,000 Common Units
Representing Limited Partner Interests

Prospectus

, 2014

Barclays
Credit Suisse
Wells Fargo Securities