Viper Energy Partners LP
Form 10-K
February 07, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
OR
o TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934

Commission File Number 001-36505

Viper Energy Partners LP
(Exact Name of Registrant As Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	46-5001985 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas (Address of Principal Executive Offices)	79701 (Zip Code)

(432) 221-7400
(Registrant Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Units Representing Limited Partner Interests	The Nasdaq Stock Market LLC (Global Select Market)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No ý
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check One):

Large Accelerated Filer	o	Accelerated Filer	ý
Non-Accelerated Filer	o	Smaller Reporting Company	o
		Emerging Growth Company	ý

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ý

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

The aggregate market value of the common units held by non-affiliates was approximately $394,183,228 on June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, based on closing prices in the daily composite list for transactions on the Nasdaq Global Select Market on such date. As of January 31, 2018, 113,882,045 common limited partner units of the registrant were outstanding.

Documents Incorporated By Reference: None

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and natural gas industry terms used in this Annual Report on Form 10-K (the "Annual Report" or this "report"):

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 report in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Barrels per day.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	Barrels of oil equivalent per day.
British Thermal Unit or Btu	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Completion	The process of treating a 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 that is primarily natural gas.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
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	Acreage allocated or assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas 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 well	A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.
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.
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	The sum of the fractional working interest owned in gross acres.
Net royalty acres	Gross acreage multiplied by the average royalty interest.
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.
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 or operations.
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 economic 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.

GLOSSARY OF CERTAIN OTHER TERMS

The following is a glossary of certain other terms used in this report:

Delaware Act	Delaware Revised Uniform Limited Partnership Act.
Diamondback	Diamondback Energy, Inc., a Delaware corporation.
EPA	U.S. Environmental Protection Agency.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States.
General partner	Viper Energy Partners GP LLC, a Delaware limited liability company; the general partner of the Partnership and a wholly-owned subsidiary of Diamondback.
Inception	September 18, 2013, the date Viper Energy Partners LLC was formed.
IPO	The partnership's initial public offering of common units.
IRS	Internal Revenue Service.
LTIP	Viper Energy Partners LP Long Term Incentive Plan.
OSHA	Federal Occupational Safety and Health Act.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The first amended and restated agreement of limited partnership, dated as of June 23, 2014, entered into by the general partner and Diamondback in connection with the closing of the IPO.
Predecessor	Viper Energy Partners LLC, a Delaware limited liability company, and a wholly-owned subsidiary of the Partnership.
Ryder Scott	Ryder Scott Company, L.P.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Annual Report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project,” and similar express intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this Annual Report, including those detailed under “Item 1A. Risk Factors” in this Annual Report, could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- 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; and
- the ability of our operators to keep pace with technological advancements.

All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made. We do not intend to, and disclaim any obligation to, update or revise any forward-looking statements unless required by securities laws. 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 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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PART I

References in this Annual Report to “Viper Energy Partners LP Predecessor,” “our predecessor,” “we,” “our,” “us” or like term when used for periods prior to June 17, 2014 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 on June 23, 2014. When used for periods on and after June 17, 2014, “we,” “our,” “us” or like terms refer to Viper Energy Partners LP and its subsidiaries. Except where expressly noted otherwise, references in this Annual Report to “Diamondback” refer to Diamondback Energy, Inc. and its subsidiaries other than Viper Energy Partners LP and its subsidiaries. References in this Annual Report to “our general partner” refer to Viper Energy Partners GP LLC, a wholly owned subsidiary of Diamondback Energy, Inc.

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Overview

We are a Delaware limited partnership formed by Diamondback on February 27, 2014 to own, acquire and exploit oil and natural gas properties in North America.

Our primary business objective is to provide an attractive return to our unitholders by focusing on business results, maximizing distributions through organic growth and pursuing accretive growth opportunities through acquisitions of mineral, royalty, overriding royalty, net profits and similar 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.

Our Properties

As of December 31, 2017, our assets consisted of mineral interests underlying 247,602 gross acres, 43,843 net acres and 9,570 net royalty acres in the Permian Basin. Diamondback is the operator of approximately 36% of this acreage. As of December 31, 2017, there were 731 vertical wells and 556 horizontal wells producing on this acreage. Net production during the fourth quarter of 2017 was approximately 12,413 net BOE/d and net production for the year ended December 31, 2017 averaged 11,023 BOE/d. For the years ended December 31, 2017, 2016 and 2015, royalty revenue generated from these mineral interests was $160.2 million, $78.8 million and $74.9 million, respectively.

The estimated proved oil and natural gas reserves of our assets, as of December 31, 2017, were 38,246 MBOE based on a reserve report prepared by Ryder Scott Company, L.P., or Ryder Scott, our independent reserve engineers. Of these reserves, approximately 74% were classified as proved developed producing reserves. Proved undeveloped, or PUD, reserves included in this estimate were from 101 gross horizontal well locations. As of December 31, 2017, our proved reserves were approximately 68% oil, 16% natural gas liquids and 16% natural gas.

Our mineral interests entitle us to receive an average 3.87% royalty interest on an acreage weighted basis on all production from our approximately 247,602 gross acres with no additional future capital or operating expense required. The actual royalty percentage varies by lease and ranges from less than 1% 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. In the Spanish Trail area of Midland County, Texas where the majority of the drilling activity has been, our average royalty interest on an acreage weighted basis is 20.4% in 16,551 gross acres and Diamondback is the operator of 61% of this acreage.

Based on Diamondback's evaluation of applicable geologic and engineering data with respect to the approximate 36% of our mineral interests for which it is the operator, Diamondback had identified approximately 224 potential economic horizontal drilling locations in multiple horizons in the Spanish Trail area. 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 the portion of the Spanish Trail area in Midland County, Texas operated by others has very similar production characteristics to the portion operated by Diamondback. RSP Permian, Inc., or RSP Permian, is the operator of a majority of our properties in Spanish Trail that are not operated by Diamondback. As of December 31, 2017, RSP Permian had drilled 67 horizontal wells on this acreage, 58 of which were producing and nine were in various stages of completion. Diamondback participated with RSP Permian in the drilling of 38 of these 67 horizontal wells on shared acreage subject to our mineral interests.

In addition to our mineral interests, we own a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests. The equity interest is so minor that we have no influence over partnership operating and financial policies and we account for it under the cost method.

Our Relationship with Diamondback

Diamondback owns and controls our general partner and, as of December 31, 2017, owned approximately 64% 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 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.

In addition, neither we nor our subsidiary nor our general partner has any employees. Diamondback provides management, operating and administrative services to us and our general partner. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included elsewhere in this report.

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. Our assets consist primarily of mineral interests in the Permian Basin in West Texas. We expect the production from our mineral interests to increase as Diamondback and our other operators drill and develop our acreage without cost to us.

- 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. Since our formation, we have acquired, and may have additional opportunities from time to time in the future to acquire, mineral or other interests in producing oil and natural gas properties directly from Diamondback. 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. The majority 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 both the Midland and Delaware Basins. Production on our properties for the year ended December 31, 2017 was approximately 72% oil, 12% natural gas liquids and 16% natural gas. As of December 31, 2017, our estimated net proved reserves were comprised of approximately 68% oil, 16% natural gas liquids and 16% natural gas.

- Multi-year drilling inventory in one of North America's leading oil resource plays. Diamondback, as the operator of approximately 36% of our acreage, 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. At an assumed price of $55.00 per Bbl WTI, Diamondback had identified approximately 224 potential economic horizontal locations on the acreage Diamondback operates in its Spanish Trail area in Midland County, Texas, based on Diamondback's evaluation of applicable geologic and engineering data. These potential economic locations are in the Wolfcamp B, Lower Spraberry, Wolfcamp A, Middle Spraberry, Clearfork and Cline horizons. Diamondback's current potential horizontal location count is based on 660-foot spacing between wells in the Wolfcamp B horizon, the Lower Spraberry horizon and the Wolfcamp A horizon, 880-foot spacing between wells in the Middle Spraberry horizon, and 1,320-foot spacing in the Clearfork and Cline horizons. The ultimate inter-well spacing may vary from these distances due to different factors, which would result in a higher or lower location count. Based on horizontal wells drilled to date, Ryder Scott assigned gross reserves to PUD locations ranging from 540 MBOE for 7,500-foot laterals in the Wolfcamp B to 1,332 MBOE for 10,000-foot laterals in the Lower Spraberry. When normalized to 7,500-foot laterals, Ryder Scott assigned average PUD values of 521 MBOE for the Wolfcamp B horizon, 884 MBOE for the Lower Spraberry horizon, 607 MBOE for the Middle Spraberry and 635 MBOE for the Wolfcamp A 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 development 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.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2017, 2016 and 2015 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, 2017 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. The Executive Vice President–Reservoir Engineering of our general partner is primarily responsible for overseeing the preparation of all of our reserve estimates. The Executive Vice President–Reservoir Engineering of our general partner is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 24 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 the Executive Vice President–Reservoir Engineering of our general partner or under his direct supervision;
- review by the Executive Vice President–Reservoir Engineering of our general partner 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 the Executive Vice President–Reservoir Engineering of our general partner to the Chief Executive Officer of our general partner;
- 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, 2017, 2016 and 2015 based on the reserve reports prepared by Ryder Scott. Each reserve report has been prepared in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States.

	December 31,		
	2017	2016	2015
Estimated proved developed reserves:			
Oil (MBbls)	18,788	12,332	9,700
Natural gas (MMcf)	29,256	15,933	13,739
Natural gas liquids (MBbls)	4,536	3,247	2,205
Total (MBOE)	28,200	18,235	14,195
Estimated proved undeveloped reserves:			
Oil (MBbls)	7,097	9,012	8,677
Natural gas (MMcf)	7,139	11,158	10,569
Natural gas liquids (MBbls)	1,759	2,329	1,711
Total (MBOE)	10,046	13,200	12,150
Estimated Net Proved Reserves:			
Oil (MBbls)	25,885	21,344	18,377
Natural gas (MMcf)	36,395	27,091	24,308
Natural gas liquids (MBbls)	6,295	5,576	3,916
Total (MBOE)(1)	38,246	31,435	26,345
Percent proved developed	73.7 %	58.0 %	53.9 %

(1) Estimates of reserves as of December 31, 2017, 2016 and 2015 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 12-month periods ended December 31, 2017, 2016 and 2015, respectively, in accordance with SEC guidelines applicable to reserve estimates as of the end of such periods. 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, 2017, our proved developed reserves totaled 18,788 MBbls of oil, 29,256 MMcf of natural gas and 4,536 MBbls of natural gas liquids, for a total of 28,200 MBOE. Producing reserves were from 731 vertical wells and 556 horizontal wells, of which Diamondback was the operator of 295 vertical wells and 240 horizontal wells and RSP Permian was the operator of 107 vertical wells and 96 horizontal wells. The remaining 329 vertical wells and 220 horizontal wells were operated by various other companies. Of the total 1,287 producing wells, Diamondback had a working interest in 603 wells.

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 “Item 1A. 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.

Proved Undeveloped Reserves

As of December 31, 2017, our PUD reserves totaled 7,097 MBbls of oil, 7,139 MMcf of natural gas and 1,759 MBbls of natural gas liquids, for a total of 10,046 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Our PUD reserves were from 101 horizontal wells, of which Diamondback is the operator of 88 horizontal wells and RSP Permian is the operator of 13 horizontal wells. While there is a significant amount of activity by other operators, due to uncertainty of timing, development horizon, and other factors, no PUD locations attributable to such other operators were included in our reserve report. Of the horizontal locations, 20 are Wolfcamp B wells, 44 are Lower Spraberry wells, three are Middle Spraberry wells and 34 are Wolfcamp A wells.

All of our PUD drilling locations are scheduled to be drilled within five years from the date they were initially recorded. As of December 31, 2017, none of our total proved reserves were classified as proved developed non-producing.

Changes in PUDs that occurred during 2017 were primarily due to:

- additions of 3,004 MBOE, primarily from 40 horizontal well locations attributable to extensions resulting from strategic drilling of wells to delineate our acreage position;

- downgrade of PUDs into probable category of 767 MBOE for seven short lateral horizontal wells that are not expected to be drilled due to the lower price environment;

- the conversion of approximately 4,906 MBOE attributable to PUDs into proved developed reserves; and

- negative revisions of approximately 500 MBOE in PUDs primarily due to changes in type curves.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

We operate in one reportable segment engaged in the acquisition of oil and natural gas properties. For a description of our revenues, average sales prices and unit costs, see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.” 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:

	Year Ended December 31,		
	2017	2016	2015
Production Data:			
Oil (MBbls)	2,899	1,778	1,555
Natural gas (MMcf)	3,549	1,490	1,129
Natural gas liquids (MBbl)	533	328	239
Combined volumes (MBOE)	4,024	2,354	1,982
Daily combined volumes (BOE/d)	11,023	6,432	5,431
Average Prices:			
Oil (per Bbl)	$48.36	$40.23	$44.75
Natural gas (per Mcf)	2.62	2.08	2.36
Natural gas liquids (per Bbl)	20.02	12.84	10.85
Combined (per BOE)	39.81	33.49	37.76

Productive Wells

As of December 31, 2017, our operators owned a working interest in 1,287 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 December 31, 2017 relating to the gross, net and net royalty acreage of our mineral interests:

Basin	Gross Acreage	Net Acreage	Net Royalty Acreage
Permian	247,602	43,843	9,570

Our net interest in production from our mineral interests is based on lease royalty terms which vary from property to property. Our interest in the majority of these properties is perpetual in nature, however approximately 6.27% of the net royalty acreage consists of over-riding royalty interests which may be subject to expiration. Net royalty acres are defined as gross acreage multiplied by the average royalty interest.

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 mineral, royalty, overriding royalty, net profits and similar interests 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 these and other 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 increases during the summer months and decreases during the winter months while 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 environmental protection. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing 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.

Liability under such laws and regulations is often strict (i.e., no showing of “fault” is required) and can be joint and several. 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, 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 the Resource Conservation and Recovery Act, 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 the Resource Conservation and Recovery Act, such wastes may constitute “solid wastes” that are subject to the less stringent non-hazardous waste requirements. Moreover, the EPA or state or local governments may 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.” Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and gas waste. It has until March 2019 to determine whether any revisions are necessary. 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, which we refer to as CERCLA or the “Superfund” law, and analogous state laws, generally impose 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” are subject to strict liability that, in some circumstances, may be joint and several 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, the Oil Pollution Act 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. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The 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. On June 29, 2015, the EPA and the U.S. Army Corps of Engineers, or the USACE, jointly promulgated final rules redefining the scope of waters protected under the Clean Water Act. To the extent the rule expands the range of properties subject to the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. Following its promulgation, numerous states and industry groups challenged the rule and, on October 9, 2015, a federal court stayed the rule's implementation nationwide, pending further action in court. In response to this decision, the EPA and the USACE have resumed nationwide use of the agencies' prior regulations defining the term "waters of the United States." Further, on February 28, 2017, President Trump signed an executive order directing the relevant executive agencies to review the rules and to initiate rulemaking to rescind or revise them, as appropriate under the stated policies of protecting navigable waters from pollution while promoting economic growth, reducing uncertainty, and showing due regard for Congress and the states. On July 27, 2017, the EPA and the USACE published a proposed rule to rescind the 2015 rules, and, on November 22, 2017, the agencies published a proposed rule to maintain the status quo pending the agencies review of the 2015 rules.

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 June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants, which regulations are discussed in more detail below under the caption "–Regulation of Hydraulic Fracturing." 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 Oil Pollution Act 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 Oil Pollution Act subjects owners of facilities to strict liability that, in some circumstances, may be joint and several 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.

Non-compliance with the Clean Water Act or the Oil Pollution Act 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." Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. 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 greenhouse gases 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. In May 2010, the EPA adopted regulations establishing new greenhouse gas emissions thresholds that determine when stationary sources must obtain permits under the Prevention of Significant Deterioration, or PSD, and Title V programs of the Clean Air Act. On June 23, 2014, in Utility Air Regulatory Group v. EPA, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their greenhouse gas emissions. The Court ruled, however, that the EPA may require installation of best available control technology for greenhouse gas emissions at sources otherwise subject to the PSD and Title V programs. On August 26, 2016, the EPA proposed changes needed to bring the EPA's air permitting regulations in line with the Supreme Court's decision on greenhouse gas permitting. The proposed rule was published in the Federal Register on October 3, 2016 and the public comment period closed on December 2, 2016.

Additionally, in September 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas 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 November 2010, the EPA expanded the greenhouse gas reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. In October 2015, the EPA amended the greenhouse gas reporting rule to add the reporting of greenhouse gas emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines.

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. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances corresponding with their annual emissions of greenhouse gases. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake “ambitious efforts” to limit the average global temperature, and to conserve and enhance sinks and reservoirs of greenhouse gases. The Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. 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 have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes 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 hotter or 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, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection,” to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act.

In addition, the EPA previously announced its plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

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 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 rules seek to achieve a 95% reduction in volatile organic compounds 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. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, President Trump directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation’s energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. On June 16, 2017, the EPA published a proposed rule to stay for two years certain requirements of the 2016 regulations, including fugitive emission requirements. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions. We cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states, including Texas, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted legislation, effective September 1, 2011, requiring oil and gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. The Texas Railroad Commission adopted rules and regulations implementing this legislation that apply to all wells for which the Texas Railroad Commission issues an initial drilling permit after February 1, 2012. The law requires that the well operator disclose the list of chemical ingredients subject to the requirements of 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. Also, in May 2013, the Texas Railroad Commission adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The rules took effect in January 2014. Additionally, on October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the Texas Railroad Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Texas Railroad Commission has used this authority to deny permits for waste disposal wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, 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 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, state or local laws 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 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 states, and some counties and municipalities, in which our operators conduct business 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 our unitholders 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 plugging and abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas. 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 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 we 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 are provided on an open-access, non-discriminatory basis at cost-based rates or negotiated rates. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. 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 oil production and a 7.5% severance tax on 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 our unitholders 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 do not have any employees. We are managed and operated by the board of directors and executive officers of our general partner. All of the employees that conduct our business, including our executive officers, are employed by Diamondback.

As of December 31, 2017, Diamondback had 251 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 “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report.

Facilities

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

Availability of Partnership Reports

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available free of charge on the Investor Relations page of our website at www.viperenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

ITEM 1A. 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. 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

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of our common units could decline, and unitholders could lose all or part of their investment. Other risks are also described in “Items 1 and 2. Business and Properties” and “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

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 volumes of production sold and the prices that our operators realize from the sale of such production. In addition, the actual amount of cash we will have to distribute each quarter under our cash distribution policy 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.

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 an 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.

Our future business performance may be volatile, and our cash flows may be unstable. 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. 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 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.

In addition, our partnership agreement does not require us to pay any distributions at all. 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 volatility of oil and natural gas prices, and particularly the ongoing decline in those 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

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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;
- the price and availability of alternative fuels;
- 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; 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. 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 $26.19 per barrel, or Bbl, in February 2016 to a high of $110.62 per Bbl in September 2013. The Henry Hub spot market price of natural gas has ranged from a low of $1.49 per MMBtu in March 2016 to a high of $8.15 per MMBtu in February 2014. During 2017, WTI prices ranged from $42.48 to $60.46 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. On January 29, 2018, the WTI posted price for crude oil was $65.71 per Bbl and the Henry Hub spot market price of natural gas was $3.60 per MMBtu. If the prices of oil and natural gas decline, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be determined at the discretion of our lenders.

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.

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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 continues at current levels or decreases further, our business, results of operations 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.

Substantially all of our assets are mineral interests from which we derive royalty income. For the year ended December 31, 2017, we received approximately 61% 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. Due to the current commodity price environment, both Diamondback and RSP Permian have expressed an intent to drill and complete fewer wells on our acreage than we previously anticipated. The level, 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:

- commodity prices;
- 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 26.3% of our total estimated proved reserves as of December 31, 2017 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 reports of our independent petroleum engineers 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 further 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 currently 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 portfolio of properties, a number of our properties 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 and results of operations.

In addition to the geographic concentration of our producing properties described above, as of December 31, 2017, all of our proved reserves were attributable to the Wolfberry play in the Midland Basin. 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 us to permanently or temporarily shut-in all of our 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 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:

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- 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 year ended December 31, 2017, Diamondback, which is the operator for approximately 36% of the acreage associated with our properties, drilled a total of 100 gross wells and participated in 11 additional gross non-operated wells, of which 57 wells were completed as producing wells and 54 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.

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Our method of accounting for investments in oil and natural gas properties resulted in impairments of asset value for the years ended December 31, 2016 and 2015 and may result in further impairments in future periods.

We account for our 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 $10.07, $12.67 and $17.88 for the years ended December 31, 2017, 2016 and 2015, 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.

Impairments on proved oil and natural gas properties of $47.5 million and $3.4 million were recorded for the years ended December 31, 2016 and 2015, respectively. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2017. See “Item 7. 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.” If the prices of oil and natural gas decline, we may be required to write down the value of our oil and natural gas properties in the future, which could negatively affect our results of operations.

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, 2017, 2016 and 2015, 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 we ultimately recover being different from our reserve estimates. 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.

The estimates of reserves as of December 31, 2017, 2016 and 2015 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 12-month periods ended December 31, 2017, 2016 and 2015, respectively, in accordance with the SEC guidelines applicable to reserve estimates for such period. Commodity prices have deteriorated significantly since that time and, accordingly, using more recent prices in estimating our proved reserves, without giving effect to any acquisition activities we have executed during 2017, would result in a reduction in proved reserve volumes due to economic limits.

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 we pursue our drilling program. Moreover, we may be required to write down our proved undeveloped reserves if we do not drill those wells within the required five-year timeframe because they have become uneconomic or otherwise.

Concerns over 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 and the European, Asian and the U.S. markets contribute to economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and natural gas liquids, volatility in consumer confidence and job markets, may result in an economic slowdown or 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, 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, and certain other employees 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 than us. 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. See "Item 7. 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

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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. As of December 31, 2017, the borrowing base was set at $400.0 million, and we had $93.5 million of outstanding borrowings and $306.5 million available for future borrowings under our revolving credit facility. A 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 describes 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 our unitholders 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 our unitholders 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,

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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, regulatory changes and approvals, costs, drilling results, the availability of water and weather conditions. 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 different spacing assumptions will produce at materially different rates. 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 our unitholders 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, see “Items 1 and 2. Business and Properties.”

Acreage must be drilled before lease expiration, generally within three to five years, to hold the acreage by production. The 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.

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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 our unitholders 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. Over the past several years, parts of Texas have 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.

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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

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and injunctions limiting or prohibiting some or all of our operations. Moreover, these laws and regulations impose 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. Even if federal regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term, and at the state and local levels. See “Items 1 and 2. Business and Properties—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.

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, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of “underground injection,” to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as “Class II” Underground Injection Control wells under the Safe Drinking Water Act.

In addition, the EPA previously announced its plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

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 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 rules seek to achieve a 95% reduction in volatile organic compounds 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 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. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic

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fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states, including Texas, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For a more detailed discussion of state and local laws and initiatives concerning hydraulic fracturing, see "Items 1 and 2. Business and Properties–Regulation–Regulation of Hydraulic Fracturing."

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, 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 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, state or local laws 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 tended to increase over time. 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 regulation of greenhouse gas emissions could result in increased operating costs and reduced demand for the oil and natural gas we produce.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. The EPA has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. While we are subject to certain federal greenhouse gas monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives. For a description of existing and proposed greenhouse gas rules and regulations, see “Items 1 and 2. Business and Properties–Regulation–Environmental Regulation-Climate Change.”

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake “ambitious efforts” to limit the average global temperature, and to conserve and enhance sinks and reservoirs of greenhouse gases. The Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. However, on June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement, and begin negotiations to either re-enter or negotiate an entirely new agreement with more favorable terms for the United States. The Paris Agreement sets forth a specific exit process, whereby a party may not provide notice of its withdrawal until three years from the effective date, with such withdrawal taking effect one year from such notice. It is not clear what steps the Trump Administration plans to take to withdraw from the Paris Agreement, whether a new agreement can be negotiated, or what terms would be included in such an agreement. Furthermore, in response to the announcement, many state and local leaders have stated their intent to intensify efforts to uphold the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. 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 have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes 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 hotter or 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.

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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 our unitholders 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

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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 our unitholders 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 now or in the future were to become obsolete, our business, financial condition or results of operations and cash available for distribution could be materially and adversely affected.

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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.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, the oil and natural gas industry depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of its vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of its business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. We do not maintain specialized insurance for possible liability resulting from a cyberattack on our assets that may shut down all or part of our business.

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.

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- 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, may compete with us.

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.

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.

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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.

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:
- 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
-

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.

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Diamondback and other affiliates of our general partner 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, are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. In addition, Diamondback may compete with us for investment opportunities and may own an interest in entities that compete with us. Further, Diamondback and its affiliates, 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, and Diamondback. 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.

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. 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 own sufficient units 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. As of December 31, 2017, Diamondback owned 64% of our outstanding common units.

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.

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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.

At the time of the IPO, we and our general partner entered into an advisory services agreement with Wexford Capital LP, or Wexford, pursuant to which Wexford agreed to provide general finance and advisory services. Any fee paid would reduce the amount of cash available for distribution to our unitholders. We paid no amounts to Wexford under the advisory services agreement during 2016 and 2017. In addition, we have 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. No amounts have been paid to Diamondback under the tax sharing agreement.

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 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.

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 Exchange Act. As of December 31, 2017, Diamondback owned 64% of our common units.

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.

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.

As of December 31, 2017, we had 113,882,045 common units outstanding. Sales by holders of a substantial number of our common units in the public markets, 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 provided registration rights to Diamondback. Pursuant to these registration rights, we have registered, under the Securities Act, all of the common units owned by Diamondback for resale. 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.

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 Public Company Accounting

Oversight Board 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 Public Company Accounting Oversight Board after April 5, 2012 unless the SEC determines otherwise or (4) provide certain disclosures regarding executive compensation required of larger public companies.

If we fail to 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. 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 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 requires 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. Any failure to 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.

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. 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.

Risks Related to Recently Enacted U.S. Tax Legislation and Tax Risks to Common Unitholders

Recently enacted U.S. tax legislation as well as future U.S. tax legislations may adversely affect our business, results of operations, financial condition and cash flow.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”) that makes significant changes to U.S. federal income tax laws. Among other changes, the Tax Act (i) introduces a new deduction on certain pass-through income, (ii) repeals the partnership technical termination rule and (iii) imposes a new limitation on the deductibility of interest expense. The Tax Act is complex and far-reaching and we have not completed our analysis of the impact its enactment has on us. There may be other material adverse effects resulting

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from the Tax Act that we have not identified and that could have an adverse effect on our business, results of operations, financial condition and cash flow.

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 IRS were to treat us as a corporation for federal income tax purposes or we were to become subject to entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders could be substantially reduced.

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

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate. We would also be subject to certain state taxes. Distributions to unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to unitholders 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 have been 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 unitholders. 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. Additionally on January 24, 2017, the U.S. Treasury Department and the IRS published final regulations regarding qualifying income under Section 7704(d)(1)(E) of the Code effective as of January 19, 2017, that provide industry-specific guidance regarding whether income earned from certain activities will be treated as qualifying income. We believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the current law and the final regulations.

Any modification to the federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible for us to satisfy the requirements of the exception pursuant to which we are treated as a partnership for income tax purposes. While the Tax Act does not negatively impact the final regulations or the qualifying income exception, there is no guarantee that such proposal will not become part of any future legislation. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and our cash available for distribution to our unitholders might substantially be reduced.

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 positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the 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.

Legislation applicable to partnership tax years beginning after 2017 alters the procedures for auditing large partnerships and for assessing and collecting taxes due (including penalties and interest) as a result of a partnership-level federal income tax

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audit. If the IRS makes audit adjustments to our partnership tax returns, to the extent possible under the new rules, our general partner may cause the partnership to pay the taxes (including any applicable penalties and interest) directly to the IRS in the year in which the audit is completed or, if we are eligible, elect to cause our unitholders and former unitholders to take such audit adjustments into account. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. If we make payments of taxes and any penalties and interest directly to the IRS in the year in which the audit is completed, our cash available for distribution to our unitholders might be substantially reduced, in which case our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own common units in us during the tax year under audit.
Even if our unitholders do not receive any cash distributions from us, our unitholders will be required to pay taxes on their share of our taxable income.

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

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to them if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing a 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 they sell their common units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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), 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. Prospective unitholders who are a tax-exempt entities or non-U.S. persons should consult their tax advisor before investing in our common units.

Pursuant to the Tax Act, if a unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from distributions to the transferee amounts that should have been withheld by the transferee but were not withheld. However, the Department of the Treasury and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of interests in publicly traded partnerships. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

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 our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to a unitholder’s tax returns.

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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 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 Department of the Treasury and the IRS adopted final Treasury regulations allowing a similar monthly simplifying convention for taxable years beginning on or after August 3, 2015. However, such 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.

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, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and 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.

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

In addition to federal income taxes, our unitholders 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 such unitholders 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. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. It is a unitholder's responsibility to file all U.S. federal, foreign, state and local tax returns.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information and Cash Distributions to Unitholders

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 price per common unit, as reported by the Nasdaq Global Select Market, for the periods indicated:

Period:	High	Low	Cash Distributions per Common Unit(1)
2017			
1st Quarter	$19.38	$15.37	$ 0.302
2nd Quarter	$18.63	$15.19	$ 0.332
3rd Quarter	$18.98	$14.76	$ 0.337
4th Quarter(2)	$24.00	$18.02	$ 0.460
2016			
1st Quarter	$17.50	$12.69	$ 0.149
2nd Quarter	$20.25	$16.07	$ 0.189
3rd Quarter	$19.60	$15.10	$ 0.207
4th Quarter	$17.41	$13.53	$ 0.258

(1) Distributions are shown for the quarter in which they were generated.

(2) The Q4 2017 distribution is payable on February 26, 2018 to unitholders of record at the close of business on February 19, 2018.

There were five holders of record of our common units on January 31, 2018.

Cash Distribution Policy

The board of directors of our general partner has adopted a policy for us to distribute all available cash generated on a quarterly basis.

Cash distributions are 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 is determined by the board of directors of our general partner following the end of such quarter. Available cash for each quarter generally equals 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.

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.

Recent Sales of Unregistered Securities

On May 9, 2017, we issued 174,513 common units to Roger Letz as consideration for our acquisition of certain mineral, royalty and other interests and certain other assets from Mr. Letz. These units were issued in reliance upon the exemption from the registration requirements of the Securities Act provided by Section 4(a)(2) of the Securities Act, as sales by an issuer not involving any public offering.

Repurchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. The following selected financial data should be read in conjunction with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements and related notes, each of which is included elsewhere in this Annual Report.

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.

Presented below is our historical financial data for the periods and as of the dates indicated. The historical financial data for the years ended December 31, 2017, 2016 and 2015 and the balance sheet data as of December 31, 2017 and 2016 are derived from our audited consolidated financial statements included elsewhere in this Annual Report.

	Year Ended December 31,				Period From Inception Through December 31, 2013
	2017	2016	2015	2014	
	(in thousands)				
Statement of Operations Data:					
Royalty income	$160,163	$78,837	$74,859	$77,767	$ 14,987
Lease bonus	11,870	309	—	—	—
Total operating income	172,033	79,146	74,859	77,767	14,987
Costs and expenses:					
Production and ad valorem taxes	10,608	5,544	5,531	5,377	972
Gathering and transportation	789	415	259	—	—
Depletion	40,519	29,820	35,436	27,601	5,199
Impairment	—	47,469	3,423	—	—
General and administrative expenses	6,296	5,209	5,835	4,372	87
Total costs and expenses	58,212	88,457	50,484	37,350	6,258
Income (loss) from operations	113,821	(9,311)	24,375	40,417	8,729
Other income (expense):					
Interest expense, net	(3,164)	(2,455)	(1,110)	(487)	—
Interest expense—related party, net of capitalized interest	—	—	—	(10,755)	(5,741)
Other income, net	821	867	1,154	459	—
Total other income (expense), net	(2,343)	(1,588)	44	(10,783)	(5,741)
Net income (loss)	$111,478	$(10,899)	$24,419	$29,634	$ 2,988
Allocation of net income:					
Net income attributable to the period January 1, 2014 through June 22, 2014				$7,021	

Net income attributable to the period June 23, 2014 through December 31, 2014	22,613
Total net income	$29,634

	Year Ended December 31,				Period From Inception Through December 31, 2013
	2017	2016	2015	2014	
	(in thousands)				
Net income (loss) attributable to common limited partners per unit:					
Basic	$1.07	$(0.13)	$0.31	0.29	
Diluted	$1.07	$(0.13)	$0.31	0.29	
Statement of Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	$139,219	$68,627	$63,832	$51,813	$ 4,845
Investing activities	(344,079)	(205,721)	(43,907)	(96,815)	(4,083)
Financing activities	219,844	145,768	(34,496)	59,350	—
Other Financial Data:					
Adjusted EBITDA[(1)]	$157,556	$72,660	$68,317	$70,579	$ 13,928
Balance Sheet Data (at period end):					
Cash and cash equivalents	$24,197	$9,213	$539	15,110	
Total assets	1,013,037	670,549	529,731	537,402	
Total liabilities	99,129	122,651	34,587	2,051	
Unitholders' equity/Members' equity	913,908	547,898	495,144	535,351	

(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 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 define Adjusted EBITDA as net income (loss) plus net interest expense, interest expense–related party (net of capitalized interest), non-cash unit-based compensation expense, depletion expense and impairment expense. Adjusted EBITDA is not a measure of net income (loss) as determined by GAAP. 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. 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.

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. 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.

	Year Ended December 31,				Period From Inception Through December 31, 2013
	2017	2016	2015	2014	
	(in thousands)				
Net income (loss)	$111,478	$(10,899)	$24,419	$29,634	$ 2,988
Interest expense, net	3,164	2,455	1,110	487	—
Interest expense–related party, net of capitalized interest	—	—	—	10,755	5,741
Non-cash unit-based compensation expense	2,395	3,815	3,929	2,102	—
Depletion	40,519	29,820	35,436	27,601	5,199
Impairment	—	47,469	3,423	—	—
Adjusted EBITDA	$157,556	$72,660	$68,317	$70,579	$ 13,928

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto presented in this Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See "Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are a publicly traded Delaware limited partnership formed by 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. As of December 31, 2017, our general partner held a 100% non-economic general partner interest in us, and Diamondback had an approximate 64% limited partner interest in us.

We operate in one reportable segment engaged in the acquisition of oil and natural gas properties. Our assets consist primarily of producing oil and natural gas properties principally located in the Permian Basin of West Texas.

2017 Transactions and Recent Developments

Our Equity Offerings

In January 2017, we completed an underwritten public offering of 9,775,000 common units, which included 1,275,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. We received net proceeds from this offering of approximately $147.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which $120.5 million was used to repay the outstanding borrowings under our revolving credit agreement and the balance was used for general partnership purposes, which included additional acquisitions.

In July 2017, we completed an underwritten public offering of 16,100,000 common units, which included 2,100,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Diamondback purchased 700,000 common units, an affiliate of our general partner purchased 3,000,000 common units and certain officers and directors of Diamondback and our general partner purchased an aggregate of 114,000 common units, in each case directly from the underwriters. Following this offering, Diamondback had an approximate 64% limited partner interest in us. We received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which we used $152.8 million to repay all of the then-outstanding borrowings under our revolving credit facility and the balance was used to fund a portion of the purchase price for acquisitions and for general partnership purposes, which included additional acquisitions.

Recent Acquisitions

During 2017, we acquired mineral interests underlying 3,157 net royalty acres for an aggregate purchase price of approximately $343.1 million and, as of December 31, 2017, had mineral interests underlying 9,570 net royalty acres. We funded these acquisitions primarily with borrowings under our revolving credit facility, with a portion of the net proceeds from our January and July 2017 offerings of common units and with the issuance of 174,513 common units to a seller in a private placement in May 2017.

Since the end of the fourth quarter of 2017, we acquired from unrelated third party sellers additional mineral interests underlying 137,443 gross acres, 1,617 net acres and 900 net royalty acres in the Permian Basin and Eagle Ford Shale for an aggregate of approximately $149.4 million, subject to post-closing adjustments. These transactions included

681 net royalty acres in DeWitt, Karnes and Gonzales Counties that we acquired for approximately $123.4 million, subject to post-closing adjustment. These assets are in the core of the Eagle Ford Shale of South Texas, with internally estimated 2018 net production of 900 BOE/d (approximately 77% liquids). As of February 2, 2018, there were four rigs running on this Eagle Ford acreage, with 225 active horizontal well permits. As a result of these transactions, as of February 2, 2018, our assets included mineral interests underlying 385,046 gross acres, 45,460 net acres and 10,470 net royalty acres primarily in the Permian Basin and Eagle Ford Shale. These acquisitions were primarily funded with cash on hand and borrowings under our revolving credit facility.

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Sources of Our Revenue

Our revenues are primarily 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. Royalty income may vary significantly from period to period as a result of changes in commodity prices, production mix and volumes of production sold by our operators.

The following table presents the breakdown of our operating income for the following periods:

	Year Ended December 31,		
	2017	2016	2015
Operating income			
Royalty income			
Oil sales	81 %	90 %	93 %
Natural gas sales	5 %	4 %	4 %
Natural gas liquid sales	6 %	6 %	3 %
Lease bonus income	8 %	— %	— %
	100%	100%	100%

As a result, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2017, West Texas Intermediate posted prices ranged from $42.48 to $60.46 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. On December 29, 2017, the West Texas Intermediate posted price for crude oil was $60.46 per Bbl and the Henry Hub spot market price of natural gas was $3.69 per MMBtu. Lower prices may not only decrease our revenues, but also potentially the amount of oil and natural gas that our operators can produce economically. Lower oil and natural gas prices may also result in a reduction in the borrowing base under our credit agreement, which may be redetermined at the discretion of our lenders.

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 as of June 23, 2014. The partnership agreement requires us to reimburse our 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.

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.

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Income Tax Expense

We are 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. Diamondback does not expect any Texas margin tax to be due for the years ended December 31, 2017, 2016 and 2015.

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Results of Operations

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

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Operating Results:			
Royalty income	$160,163	$78,837	$74,859
Lease bonus	11,870	309	—
Total operating income	172,033	79,146	74,859
Costs and expenses:			
Production and ad valorem taxes	10,608	5,544	5,531
Gathering and transportation	789	415	259
Depletion	40,519	29,820	35,436
Impairment	—	47,469	3,423
General and administrative expenses	6,296	5,209	5,835
Total costs and expenses	58,212	88,457	50,484
Income (loss) from operations	113,821	(9,311)	24,375
Other income (expense):			
Interest expense, net	(3,164)	(2,455)	(1,110)
Other income, net	821	867	1,154
Total other income (expense), net	(2,343)	(1,588)	44
Net income (loss)	$111,478	$(10,899)	$24,419
Production Data:			
Oil (MBbls)	2,899	1,778	1,555
Natural gas (MMcf)	3,549	1,490	1,129
Natural gas liquids (MBbls)	533	328	239
Combined volumes (MBOE)	4,024	2,354	1,982
Daily combined volumes (BOE/d)	11,023	6,432	5,431
% Oil	72 %	76 %	78 %
Average sales prices:			
Oil, realized ($/Bbl)	$48.36	$40.23	$44.75
Natural gas realized ($/Mcf)	2.62	2.08	2.36
Natural gas liquids ($/Bbl)	20.02	12.84	10.85
Average price realized ($/BOE)	39.81	33.49	37.76
Average Costs ($/BOE)			
Production and ad valorem taxes	$2.64	$2.35	$2.79
Gathering and transportation expense	0.20	0.18	0.13
General and administrative - cash component	0.97	0.59	0.96
Total operating expense - cash	$3.81	$3.12	$3.88
General and administrative - non-cash component	$0.59	$1.62	$1.98
Interest expense	0.79	1.04	0.56
Depletion	10.07	12.67	17.88

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Comparison of the Years Ended December 31, 2017, 2016 and 2015

Royalty Income

Our royalty income for the years ended December 31, 2017, 2016 and 2015 was $160.2 million, $78.8 million and $74.9 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

During the year ended December 31, 2017, average prices received and combined volumes sold by our operators increased as compared to the year ended December 31, 2016. Although the average prices received during the year ended December 31, 2016 decreased as compared to the year ended December 31, 2015, this decrease was partially offset by an 18.8% increase in combined volumes sold by our operators.

	2017 vs. 2016			2016 vs. 2015		
	Change in prices	Production volumes(1)	Total net dollar effect of change	Change in prices	Production volumes(1)	Total net dollar effect of change
	(dollars in thousands except change in prices)					
Effect of changes in price:						
Oil	$8.13	2,899	$23,572	$(4.52)	1,778	$(8,035)
Natural gas	0.54	3,549	1,916	(0.28)	1,490	(417)
Natural gas liquids	7.18	533	3,829	1.99	328	653
Total income due to change in price			$29,317			$(7,799)
	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change
	(dollars in thousands except average prices)					
Effect of changes in production volumes:						
Oil	1,121	$ 40.23	$45,090	222	$ 44.75	$9,955
Natural gas	2,059	2.08	4,282	362	2.36	854
Natural gas liquids	205	12.84	2,637	89	10.85	968
Total income due to change in production volumes			52,009			11,777
Total change in income			$81,326			$3,978

(1) Production volumes are presented in MBbls for oil and natural gas liquids and MMcf for natural gas

Lease Bonus Income

Lease bonus income increased by $11.6 million to $11.9 million for the year ended December 31, 2017 from $0.3 million for the year ended December 31, 2016. During the year ended December 31, 2017, we received $2.8 million which was attributable to lease bonus payments to extend the term of seven leases, reflecting an average bonus of $3,442 per acre, and $9.1 million attributable to lease bonus payments on three new leases, reflecting an average bonus of $14,320 per acre. During the year ended December 31, 2016, we received $0.3 million in lease bonus payments to extend the term of six leases, reflecting an average bonus of $1,371 per acre. We had no lease bonus income for the year ended December 31, 2015.

Impairment of Oil and Gas Properties.

During the years ended December 31, 2016 and 2015, we recorded impairments of oil and gas properties of $47.5 million and $3.4 million, respectively, as a result of the significant decline in commodity prices. No impairment was recorded for the year ended December 31, 2017.

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General and Administrative Expenses

For the years ended December 31, 2017, 2016 and 2015, we incurred general and administrative expenses of $6.3 million, $5.2 million and $5.8 million, respectively. The general and administrative expenses primarily reflect costs associated with us being a publicly traded limited partnership, unit-based compensation, the amounts reimbursed to our general partner under our partnership agreement and amounts incurred under our advisory services agreement. For the year ended December 31, 2017, the General Partner received reimbursements from us of $2.5 million. For the year ended December 31, 2016, the General Partner did not receive any reimbursements from us. For the year ended December 31, 2015, the General Partner did not receive any reimbursements from us other than the $4,000 outstanding at December 31, 2014.

Net Interest Expense

Net interest expense for the years ended December 31, 2017, 2016 and 2015 was $3.2 million, $2.5 million and $1.1 million, respectively. The increase of $0.7 million in net interest expense for the year ended December 31, 2017 as compared to 2016 was due to a higher average interest rate and increased average level of outstanding borrowings. The increase of $1.3 million in net interest expense for the year ended December 31, 2016 as compared to 2015 was primarily due to a higher average level of outstanding borrowings under our credit agreement.

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 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 define Adjusted EBITDA as net income (loss) plus net interest expense, non-cash unit-based compensation expense, depletion expense and impairment expense. Adjusted EBITDA is not a measure of net income (loss) as determined by GAAP. 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. 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.

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. 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.

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Net income (loss)	$111,478	$(10,899)	$24,419
Interest expense, net	3,164	2,455	1,110
Non-cash unit-based compensation expense	2,395	3,815	3,929
Depletion	40,519	29,820	35,436
Impairment	—	47,469	3,423

Adjusted EBITDA	$157,556	$72,660	$68,317

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Liquidity and Capital Resources

Overview

Our primary sources of liquidity have been cash flows from operations and equity and debt financings, including borrowings under our credit agreement, and our primary uses of cash have been, and are expected to continue to be, to pay distributions to our unitholders and for replacement and growth capital expenditures, including the acquisition of oil and natural gas properties. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices, weather and general economic, financial, competitive, legislative, regulatory and other factors. In 2018, we believe cash flows from operations and availability under our credit agreement will provide sufficient liquidity to manage our cash needs and contractual obligations and to fund expected capital expenditures. We continually monitor market conditions and may consider issuing more equity or taking on debt if we believe conditions to be favorable.

Our partnership agreement does not require us to distribute any of the cash we generate from operations. We believe, however, that it is 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. Cash distributions are 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 is determined by the board of directors of our general partner following the end of such quarter. Available cash for each quarter generally equals 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.

The following table presents cash distributions approved by the board of directors of our general partner for the periods presented.

Declaration Date	Quarter	Amount per Common Unit	Payment Date	Amount Distributed to Diamondback
				(in thousands)
May 1, 2015	Q1 2015	$ 0.189	May 22, 2015	$ 13,385
July 31, 2015	Q2 2015	$ 0.220	August 21, 2015	$ 15,499
October 30, 2015	Q3 2015	$ 0.200	November 20, 2015	$ 14,091
February 12, 2016	Q4 2015	$ 0.228	February 26, 2016	16,063
May 2, 2016	Q1 2016	$ 0.149	May 23, 2016	$ 10,497
July 21, 2016	Q2 2016	$ 0.189	August 22, 2016	$ 13,693
October 25, 2016	Q3 2016	$ 0.207	November 18, 2016	$ 14,997
February 3, 2017	Q4 2016	$ 0.258	February 24, 2017	$ 18,692
April 28, 2017	Q1 2017	$ 0.302	May 25, 2017	$ 21,880
July 28, 2017	Q2 2017	$ 0.332	August 24, 2017	$ 24,286
October 16, 2017	Q3 2017	$ 0.337	November 14, 2017	$ 24,652
January 26, 2018	Q4 2017	$ 0.460	February 26, 2018	*

* The Q4 2017 distribution is payable on February 26, 2018 to unitholders of record at the close of business on February 19, 2018. Based on the common units held by Diamondback on February 6, 2018, the Q4 2017 distribution payable to Diamondback on February 26, 2018 will be approximately $33.6 million.

Our Credit Agreement

On July 8, 2014, we entered into a secured revolving credit agreement with Wells Fargo, as administrative agent, and Wells Fargo Securities, as sole book runner and lead arranger. The credit agreement, as amended, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on our oil and natural gas reserves and other factors (the “borrowing base”) of $400.0 million, subject to scheduled semi-annual and other elective borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. As of December 31, 2017, the borrowing base was set at $400.0 million, and we had $93.5 million of outstanding borrowings and $306.5 million available for future borrowings under our revolving credit facility.

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The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and 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 commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022. The loan is secured by substantially all of our and our subsidiary's 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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $400.0 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.

As of December 31, 2017, we were in compliance with all financial covenants under our credit agreement. 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. With certain specified exceptions, the terms and provisions of our credit agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Cash Flows

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

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Cash Flow Data:			
Net cash provided by operating activities	$139,219	$68,627	$63,832
Net cash used in investing activities	(344,079)	(205,721)	(43,907)

Net cash provided by (used in) financing activities	219,844	145,768	(34,496)
Net increase (decrease) in cash	$14,984	$8,674	$(14,571)

Operating Activities

Our operating cash flow is sensitive to many variables, the most significant of which are the volatility of prices for oil and natural gas and the volume of oil and natural gas sold by our producers. 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.

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Investing Activities

The purchase of oil and natural gas interests accounted for the majority of our cash outlays for investing activities. Net cash used in investing activities was $344.1 million, $205.7 million and $43.9 million during the years ended December 31, 2017, 2016 and 2015, respectively, related to acquisitions of royalty interests.

Financing Activities

Net cash provided by financing activities was $219.8 million during the year ended December 31, 2017, primarily related to aggregate net proceeds of $380.0 million from our public offerings of common units in January and July 2017, partially offset by $130.9 million of distributions to our unitholders and $27.0 million of net repayments under our revolving credit agreement during 2017.

Net cash provided by financing activities was $145.8 million during the year ended December 31, 2016, primarily related to $86.0 million of net borrowings under our revolving credit agreement and net proceeds of $125.0 million from our public offering of common units partially offset by $64.8 million of distributions to our unitholders during 2016.

Net cash used in financing activities of $34.5 million during the year ended December 31, 2015 primarily related to $68.6 million of distributions to our unitholders during 2015, after giving effect to $34.5 million of proceeds from borrowings under our credit facility.

Contractual Obligations

The following table summarizes our contractual obligations and commitments as of December 31, 2017.

	Payments Due by Period				
	Total	2018	2019-2020	2021-2022	Thereafter
	(in thousands)				
Credit agreement[(1)]	$93,500	$—	$ —	$ 93,500	$ —
Interest and commitment fees under our credit agreement[(2)]	$5,555	$1,149	$ 2,299	$ 2,107	$ —
	$99,055	$1,149	$ 2,299	$ 95,607	$ —

(1) Includes the outstanding principal amount under the credit agreement, the table does not include interest expense or other fees payable under this floating rate facility as we cannot predict the timing of future borrowings and repayments or interest rates to be charged.

(2) This table reflects only the minimum amount of interest and commitment fees due, which as of December 31, 2017 includes a commitment fee equal to 0.375% per year of the unused portion of the borrowing base of our credit agreement. The table does not include interest expense as we cannot predict the timing of future borrowings and repayments or interest rates to be charged. See Note 5–Debt to our consolidated financial statements and related notes included elsewhere in this Annual Report.

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 GAAP. 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 Annual Report 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.

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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 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.

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 Discounted Future Net Cash Flows

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net cash flows. The SEC has defined proved reserves as the estimated quantities of oil and natural 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 natural 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 7–Unit-Based Compensation to our audited consolidated financial statements included elsewhere in this Annual Report. 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 year ended December 31, 2017, were completed using a Black-Scholes option valuation model, which requires us to make several assumptions.

Recent Accounting Pronouncements

Recently Issued Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers.

We will adopt this Accounting Standards Update effective January 1, 2018 using the modified retrospective approach. We have reviewed various contracts that represent our material revenue streams and determined that there will be no impact to our financial position, results of operations or liquidity. Upon adoption of this Accounting Standards Update, we will not be required to record a cumulative effect adjustment due to the new Accounting Standards Update not having a quantitative impact compared to existing GAAP. Also, upon adoption of this Accounting Standards Update, we will not be required to alter our existing information technology and internal controls outside of ongoing contract review processes in order to identify impacts of future revenue contracts entered into by us. We do not anticipate the disclosure requirements under the Accounting Standards Update to have a material change on how we present information regarding our revenue streams as compared to existing GAAP.

In January 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-01, "Financial Instruments–Overall". This update applies to any entity that holds financial assets or owes financial liabilities. This update requires equity investments (except for those accounted for under the equity method or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. We will adopt this standard effective January 1, 2018 by means of a cumulative-effect adjustment which will decrease Unitholders' Equity and bring the fair value of our investment to $15.2 million or $15.20 per unit for that investment.

In November 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-18, "Statement of Cash Flows - Restricted Cash". This update affects entities that have restricted cash or restricted cash equivalents. We will adopt this updated retrospectively effective January 1, 2018. The adoption of this update will only effect the presentation on the Statement of Cash Flows.

In January 2017, the Financial Accounting Standards Board issued Accounting Standards Update 2017-01, "Business Combinations - Clarifying the Definition of a Business". This update apples to all entities that must determine whether they acquired or sold a business. This update provides a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. We will adopt this update prospectively effective January 1, 2018. The adoption of this update will not have an impact on our financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, "Leases". This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. As of the filing date, we were not the lessor or lessee of any leases other than mineral leases which were excluded from the scope of this Accounting Standards Update. Therefore, we believe the adoption of this update will not have an impact on our financial position, results of operations or liquidity.

In June 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-13, "Financial Instruments - Credit Losses". This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We do not believe the adoption of this standard will have an impact on our financial statements since we do not have a history of credit losses.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2017, 2016 and 2015. Although the impact of inflation has been insignificant in recent years, it continues to be a factor in the U.S. economy and our operators do experience inflationary pressure on the costs of oilfield services and equipment as drilling activity increases in the areas in which our properties are located.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses.

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, particularly during the past year, 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 year ended December 31, 2017, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (US) Company, or Shell Trading (47%) and RSP Permian LLC (23%). For the year ended December 31, 2016, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (57%) and RSP Permian LLC (32%). For the year ended December 31, 2015, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (68%) and RSP Permian LLC (25%). 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 credit agreement. The terms of our credit agreement 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 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in

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each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% in the case of the alternative base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. As of December 31, 2017, we had $93.5 million in outstanding borrowings under our credit agreement with a weighted average rate of 3.19%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $0.9 million based on the $93.5 million outstanding in the aggregate under our credit agreement on December 31, 2017.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures. Under the direction of the Chief Executive Officer and Chief Financial Officer of our general partner, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer of our general partner, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of December 31, 2017, an evaluation was performed under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of our general partner, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon the evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner have concluded that as of December 31, 2017, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during the year ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of our general partner is responsible for establishing and maintaining adequate internal control over financial reporting of the Partnership. The Partnership's internal control over financial reporting is a process designed under the supervision of the Chief Executive Officer and Chief Financial Officer of our general partner to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Partnership's financial statements for external purposes in accordance with generally accepted accounting principles.

Management conducted an evaluation of the effectiveness of the Partnership's internal control over financial reporting based on the framework in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2013 Internal Control-Integrated Framework, management did not identify any material weaknesses in the Partnership's internal control over financial reporting and determined that the Partnership maintained effective internal control over financial reporting as of December 31, 2017.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As an entity with less than $1 billion in revenue during our last fiscal year, we qualify as an "emerging growth company" as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. As an emerging growth company, we may take advantage of specified reduced reporting and other regulatory requirements for up to five years from our IPO that are otherwise applicable generally to public companies. As an emerging growth company, we are taking advantage of the exemption from the auditor attestation requirement on the effectiveness of our system of internal control over financial reporting.

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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 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. The executive officers listed below allocate their time between managing our business and the business of Diamondback.

Executive Officers and Directors of Our General Partner

The following table shows information for the executive officers and directors of our general partner as of January 31, 2018. 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	Position With Our General Partner
Travis D. Stice	56	Chief Executive Officer, Director
Kaes Van't Hof	31	President
Teresa L. Dick	48	Chief Financial Officer, Executive Vice President and Assistant Secretary
Russell Pantermuehl	58	Executive Vice President—Reservoir Engineering
Thomas F. Hawkins	63	Senior Vice President—Land
Randall J. Holder	64	Executive Vice President, General Counsel and Secretary
Paul S. Molnar	61	Executive Vice President—Exploration and Business Development
Steven E. West	57	Executive Chairman, Director
W. Wesley Perry	61	Director
Spencer D. Armour	63	Director
Michael L. Hollis	42	Director
James L. Rubin	33	Director
Rosalind Redfern Grover	76	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 positions with us and Diamondback, Mr. Stice served as its President and Chief Operating Officer from April 2011 to January 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.

Kaes Van't Hof. Mr. Van't Hof has served as President of our general partner since March 2017. Mr. Van't Hof joined Diamondback in July 2016 as Vice President-Strategy and Corporate Development and was promoted to Senior Vice President-Strategy and Corporate Development in February 2017. Prior to his positions with us and Diamondback, Mr. Van't Hof served as Chief Executive Officer for Bison Drilling and Field Services from September 2012 to June 2016. From August 2011 to August 2012, Mr. Van't Hof was an analyst for Wexford Capital LP responsible for developing operating models and business plans, including in connection with our initial public offering, and before that worked for the Investment Banking-Financial Institutions Group of Citigroup Global Markets, Inc. from February 2010 to July 2011. Mr. Van't Hof was a professional tennis player from May 2008 to January 2010. Mr. Van't Hof received a Bachelor of Science in Accounting and Business Administration from the University of Southern California.

Teresa L. Dick. Ms. Dick has served as Chief Financial Officer and Executive Vice President of our general partner since February 2017 and served as Chief Financial Officer and Senior Vice President from February 2014 to February 2017. She has also served as Diamondback's Executive Vice President and Chief Financial Officer since February 2017, as its Chief Financial Officer and Senior Vice President from November 2009 to February 2017 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 Executive Vice President-Reservoir Engineering of our general partner since February 2017 and served as Vice President-Reservoir Engineering from February 2014 to February 2017. He has also served as Diamondback's Executive Vice President-Reservoir Engineering since February 2017, and served as Vice President-Reservoir Engineering from August 2011 to February 2017. Prior to his positions with us and 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.

Thomas F. Hawkins. Mr. Hawkins has served as Senior Vice President-Land of our general partner since March 2017. He has also served as Diamondback's Senior Vice President-Land since March 2017. Prior to his positions with us and Diamondback, Mr. Hawkins was an independent consultant for land activities from July 2016 to February 2017. Mr. Hawkins has over 38 years of experience in the oil and gas industry. Mr. Hawkins spent seven years with Oasis Petroleum Inc., an oil and gas company, as its Senior Vice President of Land or in related capacities from March 2009 to June 2016. Until February 2009, Mr. Hawkins spent 31 years with ConocoPhillips and Burlington Resources (which ConocoPhillips acquired in 2006). During that time, Mr. Hawkins held various operations and managerial positions in the land, marketing, planning and the corporate acquisitions and divestitures groups. Mr. Hawkins has worked in several major regions in the continental United States, including the San Juan Basin, the Williston Basin and the Austin Chalk/Wilcox Trends in South Texas. Mr. Hawkins holds a Bachelor of Business Administration in Finance from the University of Texas at El Paso.

Randall J. Holder. Mr. Holder has served as Executive Vice President, General Counsel and Secretary of our general partner since February 2017 and served as Vice President, General Counsel and Secretary from February 2014 to February 2017. He has also served as Diamondback's Executive Vice President, General Counsel and Secretary since February 2017, and served as its Vice President, General Counsel and Secretary from October 2012 to February 2017, and as General Counsel and Vice President from November 2011 to October 2012. Prior to his positions with us and 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.

Paul S. Molnar. Mr. Molnar has served as our Executive Vice President-Exploration and Business Development since January 2017 and served as our Vice President-Geoscience from February 2014 to January 2017. Mr. Molnar joined Diamondback in August 2011 as Vice President-Geoscience and was promoted to Executive Vice President-Exploration and Business Development effective January 1, 2017. Prior to joining us and Diamondback, Mr. Molnar served as a Senior District Geologist for Samson Investment Company, an oil and gas exploration company, from March 2011 to August 2011. Mr. Molnar worked as an asset supervisor and geosciences supervisor for ConocoPhillips Company from April 2006 to February 2011. Mr. Molnar also worked as a geologic advisor for Burlington Resources, an oil and gas exploration company, from December 1996 to March 2006. Mr. Molnar has over 31 years of industry experience. Mr. Molnar received a Bachelor of Science degree in Geoscience from the State University of New York, College at Buffalo and a Master of Science degree in Geology from the State University of New York, University at Buffalo.

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. From January 2011 until December 2016, Mr. West was 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. Mr. Perry has served as a director of Genie Energy Ltd., an independent retail energy provider, since October 2011, currently serves as the chair of its audit committee and a member of its compensation, nominating, corporate governance and technology committees and has served as the chairman of the board of directors of Genie Energy International Corporation since September 2009. Mr. Perry also serves as manager of PBEX, LLC, an oil and gas exploration and development company, a position he has held since July 2012. Mr. Perry has served as manager of S.E.S. Investments, Ltd., an oil and gas investment company, since 1985. He has served as Chief Executive Officer of E.G.L. Resources, Inc., an oil and gas production company, since July 2008 and served as its President from 2003 to July 2008. Mr. Perry was a director of UTG, Inc., an insurance holding company, from 2001 to 2013 and served on its Audit Committee. Mr. Perry served on the Midland City Council from 2002 to 2008 and as Mayor of Midland from 2008 through 2014. He is the President of the Milagros Foundation and a trustee of the Abell-Hangar Foundation. He has 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.

Spencer D. Armour. Mr. Armour has been a member of the board of directors of our general partner since July 2017. Mr. Armour has over 30 years of executive and entrepreneurial experience in the energy services industry. Mr. Armour currently serves as President of PT Petroleum LLC in Midland, Texas. He was the Vice President of Corporate Development for Basic Energy Services, Inc. from 2007 to 2008, which acquired Sledge Drilling Corp., a company Mr. Armour co-founded and served as Chief Executive Officer for from 2005 to 2006. From 1998 through

2005, he served as Executive Vice President of Patterson-UTI Energy, Inc., which acquired Lone Star Mud, Inc., a company Mr. Armour founded and served as President from 1986 to 1997. Mr. Armour has served as a director of ProPetro Holding Corp. since February 2013. Mr. Armour also served on the Patterson-UTI Board of Directors from 1999 through 2001. Mr. Armour received a Bachelor of Science in Economics from the University of Houston and was appointed to the University of Houston System Board of Regents in 2011 by former Texas Governor Rick Perry. We believe that Mr. Armour's extensive experience in the oil and gas industry qualify 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 Chief Operating Officer of Diamondback since July 2015 and before that served as Vice President-Drilling of

Diamondback since September 2011. Prior to his positions 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.

Rosalind Redfern Grover. Ms. Grover has been a member of the board of directors of our general partner since December 2014. Ms. Grover served as Chairman of the Board of Flag-Redfern Oil Company until the company was sold to Kerr-McGee Corporation in 1988. She has served as the President of Redfern Enterprises, Inc., an independent oil and gas producer, since 1989 and as the Chief Executive Officer of Redfern & Grover Resources, LLC, an independent oil and gas producer, since 2014. Ms. Grover holds Bachelors and Masters degrees from the University of Arizona.

We believe that Ms. Grover's extensive experience in the oil and gas industry, including with oil and gas partnerships, qualifies her to serve on the board of directors of our general partner.

Director Independence

The board of directors of our general partner has seven directors, three of whom are independent as defined under the independence standards established by Nasdaq and the Exchange Act. W. Wesley Perry, Spencer D. Armour and Rosalind Redfern Grover serve as the independent members of the board of directors of our general partner. 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.

Board Leadership Structure and Role in Risk Oversight

Leadership of our general partner's board of directors is vested in the Executive Chairman. Steven E. West serves as the Executive Chairman of the board of directors of our general partner and as Chairman of the board of Diamondback. Our general partner's board of directors has determined that the combined roles of Executive Chairman of the board of directors of our general partner and Chairman of the board of Diamondback allows the board of directors to take advantage of the leadership skills of Mr. West and that Mr. West's in-depth knowledge of, and experience in, our business, history, structure and organization facilitates timely communications between the board of directors of Diamondback and the board of directors of our general partner.

As a partnership engaged in the oil and natural gas industry, we face a number of risks, including risks associated with supply of and demand for oil and natural gas, volatility of oil and natural gas prices, exploring for, developing, producing and delivering oil and natural gas, declining production, environmental and other government regulations and taxes, weather conditions that can affect oil and natural gas operations over a wide area, adequacy of our insurance coverage, political instability or armed conflict in oil and natural gas producing regions and the overall economic environment. Management is responsible for the day-to-day management of risks we face as a partnership, while the board of directors of our general partner, as a whole and through its committees, has responsibility for the oversight of risk management. In its risk oversight role, the board of directors of our general partner has the responsibility to satisfy itself that the risk management processes designed and implemented by management are adequate and functioning as designed.

The board of directors of our general partner believes that full and open communication between management and the board is essential for effective risk management and oversight. The Executive Chairman of the board of directors of our general partner meets regularly with the Chief Executive Officer and the Chief Financial Officer to discuss strategy and risks facing the partnership. Executive officers may attend the board meetings of our general partner and are available to address any questions or concerns raised by the board on risk management-related and any other matters. Other members of our management team periodically attend the board meetings or are otherwise available to confer with the board to the extent their expertise is required to address risk management matters. Periodically, the board of directors of our general partner receives presentations from senior management on strategic matters involving our operations. During such meetings, the board also discusses strategies, key challenges, and risks and opportunities for the partnership with senior management.

While the board of directors of our general partner is ultimately responsible for risk oversight at the partnership, its two committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. The audit committee assists the board in fulfilling its oversight responsibilities with respect to risk management in the areas of financial reporting, internal controls and compliance with legal and regulatory requirements, and discusses policies with respect to risk assessment and risk management. The conflicts committee assists the board in fulfilling its oversight responsibilities with respect to specific matters that the board believes may involve conflicts of interest.

Meetings of the Board of Directors

During 2017, the board of directors of our general partner met three times. Each director attended at least 86% of the meetings of the board and the committees of the board on which he or she served that occurred during 2017.

Communications with Directors

Unitholders or interested parties may communicate directly with the board of directors of our general partner, any committee of the board, any independent directors, or any one director, by sending written correspondence by mail addressed to the board, committee or director to the attention of our Secretary at the following address: c/o Secretary, Viper Energy Partners LP, 500 West Texas, Suite 1200, Midland, Texas. Communications are distributed to the board of directors, committee of the board of directors, or director as appropriate, depending on the facts and circumstances outlined in the communication. Commercial solicitations or communications will not be forwarded.

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 or a nominating and corporate governance committee. Rather, the board of directors of our general partner has authority over compensation matters and nominating and corporate governance matters.

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 is also 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. The audit committee met four times during 2017. The audit committee has adopted a charter, which is available on our website under the “corporate governance” section at http://ir.viperenergy.com.

W. Wesley Perry, Spencer D. Armour and Rosalind Redfern Grover currently serve on the audit committee, and Mr. Perry serves as the chairman. The board or directors of our general partner has determined that each of W. Wesley Perry, Spencer D. Armour and Rosalind Redfern Grover meet the independence and experience standards established by Nasdaq and the Exchange Act and that Mr. Perry is an “audit committee financial expert” as defined under SEC rules.

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. W. Wesley Perry, Spencer D. Armour and Rosalind Redfern Grover are the members of the conflicts committee, which was formed in January 2015.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and officers, and persons who own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act, to file reports of beneficial ownership and reports of changes in beneficial ownership of such securities with the SEC. Directors, officers and greater than 10% unitholders are required by SEC regulations to furnish to us copies of all Section 16(a) forms they file with the SEC.

Based solely on a review of the copies of reports on Forms 3, 4 and 5 and amendments thereto furnished to us and written representations from the executive officers and directors of our general partner, we believe that during the year ended December 31, 2017 the officers and directors of our general partner and beneficial owners of more than 10% of our equity securities registered pursuant to Section 12 were in compliance with the applicable requirements of Section 16(a).

Corporate Governance

The board of directors of our general partner has adopted a Code of Business Conduct and Ethics, or Code of Ethics, that applies to all employees, including executive officers, and directors. Amendments to or waivers from the Code of Ethics will be disclosed on our website. We have also made the Code of Ethics available on our website under the "Corporate Governance" section at http://ir.viperenergy.com.

Reimbursement of Expenses of our General Partner

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.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

As is commonly the case for publicly traded limited partnerships, we have no officers. 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. Our general partner's 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 allocate their time between managing our business and managing the business of Diamondback. Since all of these executive officers are employed by Diamondback or one of its subsidiaries, the responsibility and authority for compensation-related decisions for them resides with Diamondback's 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 are not 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 are made to executive officers, key employees and non-employee directors under the LTIP are made by the board of directors of our general partner. 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, the executive officers of our general partner 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 reimburse Diamondback for

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compensation related expenses attributable to the portion of the executive's time dedicated to providing services to us. Although we 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 have no control over such costs and did not establish and do not direct the compensation policies or practices of Diamondback. Except with respect to awards granted under the LTIP, compensation paid or awarded by us in 2017 consisted 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.

A full discussion of the compensation programs for Diamondback's executive officers and the policies and philosophy of the compensation committee of Diamondback's board of directors will be set forth in Diamondback's 2018 proxy statement under the heading "Compensation Discussion and Analysis." Specifically, compensation paid directly by us through our LTIP or indirectly by us through reimbursement pursuant to our partnership agreement will be included in the amounts set forth in certain of the tables set forth in Diamondback's 2018 proxy statement, with awards outstanding pursuant to our LTIP separately identified.

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 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.

Our general partner has made grants under the LTIP of (a) phantom units to the non-employee directors of our general partner (see "Director Compensation" below for information regarding those awards) and (b) at the time of our IPO, an aggregate of 2,500,000 unit options to the executive officers of our general partner. Each unit option entitled the recipient to purchase one of our common units. In accordance with the LTIP, the exercise price of the unit options granted could not be less than the market value of our common units on the date of grant. The unit options had an exercise price of $26.00 per unit, which was the price to the public in our IPO. A third of the unit options vested each year on the anniversary of their grant. All of the unit options automatically expired unexercised on December 31, 2017.

Administration

The LTIP is administered by the board of directors of our general partner pursuant to its terms and all applicable state, federal, or other rules or laws. The board of directors of our general partner 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.

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.

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Compensation Report

Neither we nor the board of directors of our general partner has a compensation committee. The board of directors of our general partner has reviewed and discussed the Compensation Discussion and Analysis set forth above. Based on this review and discussion, the board of directors of our general partner has approved the Compensation Discussion and Analysis for inclusion in this Annual Report.

The Board of Directors of Viper Energy Partners GP LLC
Travis D. Stice
Steven E. West
W. Wesley Perry
Spencer D. Armour
Michael L. Hollis
James L. Rubin
Rosalind Redfern Grover

Director Compensation

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.

Prior to July 1, 2017, each non-employee director received a compensation package that consisted 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 received 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. Effective July 1, 2017, the board of directors approved a change that increased the annual cash retainer to $60,000 and eliminated all meeting fees.

In addition, effective July 1, 2017, each non-employee director receives an equity award of phantom units under the LTIP granted annually at the close of business on July 10th of each year or, if not a business day, the first business day thereafter; provided however, that the grant date for 2017 was July 1, 2017. The number of phantom units awarded is calculated by dividing $100,000 by the average closing price of our common units for the five trading days immediately proceeding the date of grant. The awards vest on the first anniversary of the grate date. Our directors are also reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or its committees.

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

The following table sets forth the aggregate dollar amount of all fees paid to each of the non-employee directors of our general partner during 2017 for their services on the board:

Name	Fees Earned or Paid in cash (a)	Unit Awards (b)	Total
Spencer D. Armour (e)	$72,875	$107,627	$180,502

Rosalind Redfern Grover (c)(d)(e)	75,375	107,627	183,002
W. Wesley Perry (c)(d)(e)	85,375	107,627	193,002
James L. Rubin (c)(d)(e)	58,375	107,627	166,002
Steven E. West (c)(d)(e)	58,875	107,627	166,502

(a) This column reflects the value of a director’s annual retainer, as well as the additional payments for committee membership, committee chairmanship and meeting attendance.

(b) The amount in this column represents the aggregate grant date fair value of phantom units granted in the fiscal year calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, “Compensation - Stock Compensation.”

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(c) Each of Ms. Grover and Messrs. Perry, Rubin and West received a grant of 4,938 phantom units on August 27, 2015, of which 1,646 vested and settled on the date of grant, 1,646 vested and settled on June 17, 2016 and 1,646 vested and settled on June 17, 2017, pursuant to the LTIP, with each unit having a grant date fair value of $15.48. Each phantom unit is the economic equivalent of one of our common units.

(d) Each of Ms. Grover and Messrs. Perry, Rubin and West received a grant of 5,424 phantom units on August 24, 2016, of which 1,808 vested and settled on the date of grant and 1,808 vested and settled on June 17, 2017, pursuant to the LTIP, with each unit having a grant date fair value of $16.57. Each of Ms. Grover's and Messrs. Perry's, Rubin's and West's remaining 1,808 phantom units will vest and settle on June 17, 2018. Each phantom unit is the economic equivalent of one of our common units.

(e) Each of Ms. Grover and Messrs. Armour, Perry, Rubin and West received a grant of 6,414 phantom units on July 25, 2017, which will vest and settle on July 1, 2018, pursuant to the LTIP, with each unit having a grant date fair value of $16.78. Each phantom unit is the economic equivalent of one of our common units.

Messrs. Stice and Hollis are both directors of our general partner, but Mr. Stice is also an executive officer of our general partner and both Messrs. Stice and Hollis are employees of Diamondback E&P LLC. Each of Messrs. Stice and Hollis has received awards pursuant to the LTIP for his service as an executive officer or employee, respectively, and unrelated to his service as directors. These awards are reflected in the tables contained in Diamondback's 2018 proxy statement under the heading "Compensation Discussion and Analysis."

Compensation Committee Interlocks and Insider Participation

As previously noted, our general partner's board of directors is not required to maintain, and does not maintain, a separate compensation committee. Mr. Hollis, a director of our general partner, is also an executive officer of Diamondback. Mr. Stice, a director and executive officer of our general partner, is also a director and executive officer of Diamondback. However, all compensation decisions with respect to Messrs. Stice and Hollis are made by Diamondback and Messrs. Stice and Hollis do not receive any compensation directly from us or our general partner except for awards under our LTIP. As described in "–Compensation Discussion and Analysis," decisions regarding the compensation of our general partner's executive officers are made by Diamondback. Please read "Items 1 and 2. Business and Properties–Our Relationship with Diamondback" and "Item 13. Certain Relationships and Related Transactions, and Director Independence" for more information about relationships among us, our general partner and Diamondback.

Compensation Policies and Practices as They Relate to Risk Management

We do not have any employees. We are managed and operated by the directors and officers of our general partner and employees of Diamondback perform services on our behalf. Please read "–Compensation Discussion and Analysis" and "Items 1 and 2. Business and Properties–Our Relationship with Diamondback" for more information about this arrangement. For an analysis of any risks arising from Diamondback's compensation policies and practices, please read Diamondback's 2018 proxy statement. We have made awards of unit options subject to time-based vesting under our LTIP, which we believe drive a long-term perspective and which we believe make it less likely that executive officers will take unreasonable risks because the unit options retain value even in a depressed market.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The following table presents information regarding the beneficial ownership of our common units as of January 25, 2018 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.

Name of Beneficial Owner	Common Units Beneficially Owned[(1)]	Percentage of Common Units Beneficially Owned
Diamondback Energy, Inc.[(2)]	73,150,000	64%
Viper Energy Partners GP LLC	—	—
Travis D. Stice[(3)]	68,311	*
Kaes Van't Hof[(4)]	16,026	*
Teresa L. Dick[(5)]	11,540	*
Russell Pantermuehl[(5)]	48,487	*
Thomas F. Hawkins	—	—
Randall J. Holder[(5)]	14,622	*
Paul S. Molnar[(5)]	18,487	*
Steven E. West [(6)]	48,265	—
W. Wesley Perry [(7)]	34,220	*
Spencer D. Armour[(8)]	—	*
Michael L. Hollis [(9)]	78,461	*
James L. Rubin [(10)]	—	—
Rosalind Redfern Grover [(7)]	8,554	*
All directors and executive officers as a group (13 persons)	346,973	*

*Less than 1%

(1) Beneficial ownership is determined in accordance with SEC rules. In computing percentage ownership of each person, (i) common units subject to options held by that person that are exercisable as of January 25, 2018 and (ii) common units subject to options or phantom units held by that person that are exercisable or vesting within 60 days of January 25, 2018 are all deemed to be beneficially owned. These common units, however, are not deemed outstanding for the purpose of computing the percentage ownership of each other person. The percentage of common units beneficially owned is based on 113,882,045 common units outstanding as of January 25, 2018. Unless otherwise indicated, all amounts exclude common units issuable upon the exercise of outstanding options and vesting of phantom units that are not exercisable and/or vested as of January 25, 2018 or within 60 days of January 25, 2018. Unless otherwise noted, the address for each beneficial owner listed below is 500 West Texas Avenue, Suite 1200, Midland, Texas 79701.

(2) 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.

(3)

All of these units or options, as applicable, are held by Stice Investments, Ltd., which is managed by Stice Management, LLC, its general partner. Mr. Stice and his spouse hold 100% of the membership interests in Stice Management, LLC, of which Mr. Stice is the manager. Excludes 1,250,000 unit options that expired as of December 31, 2017.

(4) Includes (i) 7,600 unit options granted to Mr. Van't Hof, which vested on January 1, 2018, and will be automatically exercisable upon the earlier to occur of December 31, 2018 and the occurrence of a change in control and (ii) 5,346 phantom units, which will vest on February 16, 2018. Excludes 10,692 phantom units, which will vest in two equal installments beginning on February 16, 2019.

(5) Excludes 125,000, 250,000, 125,000 and 125,000 unit options held by Ms. Dick, Mr. Pantermuehl, Mr. Holder and Mr. Molnar, respectively, all of which expired as of December 31, 2017.

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(6) Excludes 1,808 unvested phantom units that will vest on June 17, 2018 and 6,414 unvested phantom units that will vest on July 1, 2018. Also excludes 11,766 common units (representing vested phantom units previously granted to Mr. West), all of which have been assigned by Mr. West to Wexford under the terms of his previous employment with Wexford. Mr. West retired from Wexford as of December 31, 2016.

(7) Excludes 1,808 unvested phantom units that will vest on June 17, 2018 and 6,414 unvested phantom units that will vest on July 1, 2018.

(8) Excludes 6,414 unvested phantom units that will vest on July 1, 2018.

(9) All of the units or options, as applicable, are held by MBH Investments, Ltd., which is managed by MBH Financial, LLC, its general partner. Mr. Hollis, his spouse and the Hollis 2014 Irrevocable Trust hold 100% of the membership interests in MBH Financial, LLC, of which Mr. Hollis is the manager. Excludes 250,000 unit options that expired as of December 31, 2017.

(10) Excludes 15,220 common units (representing vested phantom units previously granted to such Mr. Rubin), 1,808 unvested phantom units that will vest on June 17, 2018 and 6,414 unvested phantom units that will vest on July 1, 2018, all of which have been assigned by Mr. Rubin to Wexford under the terms of his employment with Wexford.

The following table sets forth, as of January 25, 2018, the number of shares of common stock of Diamondback beneficially owned by each of the directors and executive officers of our general partner and all directors and executive officers of our general partner as a group.

Name of Beneficial Owner	Shares of Diamondback Common Stock Beneficially Owned[(1)] Amount and Nature of Beneficial Ownership	Percentage of Class
Travis D. Stice[(2)]	189,932	*
Kaes Van't Hof[(3)]	2,528	*
Teresa L. Dick[(4)]	18,810	*
Russell Pantermuehl[(5)]	55,066	*
Thomas F. Hawkins[(6)]	2,600	*
Randall J. Holder[(7)]	4,955	*
Paul S. Molnar[(8)]	28,663	*
Steven E. West[(9)]	3,379	*
W. Wesley Perry	—	—
Spencer D. Armour	—	—
Michael L. Hollis[(10)]	56,470	*
James L. Rubin	—	—
Rosalind Redfern Grover	—	—
All directors and executive officers as a group (13 persons)	362,403	*

*Less than 1%

(1) Beneficial ownership is determined in accordance with SEC rules. In computing percentage ownership of each person, (i) shares of common stock subject to options held by that person that are exercisable as of January 25, 2018 and (ii) shares of common stock subject to options or restricted stock units held by that person that are exercisable or vesting within 60 days of January 25, 2018, are all 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 98,167,289 shares of common stock outstanding as of January 25, 2018. 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 January 25, 2018 or within 60 days of January 25, 2018.

(2) All of these shares are held by Stice Investments, Ltd., which is managed by Stice Management, LLC, its general partner. Mr. Stice and his spouse hold 100% of the membership interests in Stice Management, LLC, of which Mr. Stice is the manager. Excludes 7,410 restricted stock units, which will vest on February 16, 2019. Also excludes (i) 180,338 performance-based restricted stock units awarded to Mr. Stice on January 19, 2016, which vested on December 31, 2017(representing 200% vesting of the originally reported amount) subject to final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ended on December 31, 2017 by Diamondback's compensation committee, and (ii) 45,084 performance-based restricted stock units awarded to Mr. Stice on January 19, 2016, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending December 31, 2018. Also excludes (i) 11,115 performance-based restricted stock units awarded to Mr. Stice on February 16, 2017, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ending on December 31, 2018, and (ii) 22,230 performance-based restricted stock

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units awarded to Mr. Stice on February 16, 2017, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending December 31, 2019.

(3) Excludes 567 restricted stock units, which will vest on September 1, 2018 and 1,300 restricted stock units, which will vest on February 16, 2019.

(4) Excludes 1,950 restricted stock units, which will vest on February 16, 2019. Also excludes (i) 12,022 performance-based restricted stock units awarded to Ms. Dick on January 19, 2016, which vested on December 31, 2017 (representing 200% vesting of the originally reported amount) subject to final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ended on December 31, 2017 by Diamondback's compensation committee, and (ii) 3,006 performance-based restricted stock units awarded to Ms. Dick on January 19, 2016, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending December 31, 2018. Also excludes (i) 2,925 performance-based restricted stock units awarded to Ms. Dick on February 16, 2017, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ending on December 31, 2018, and (ii) 5,850 performance-based restricted stock units awarded to Ms. Dick on February 16, 2017, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending December 31, 2019.

(5) Excludes 3,900 restricted stock units, which will vest on February 16, 2019. Also excludes (i) 48,090 performance-based restricted stock units awarded to Mr. Pantermuehl on January 19, 2016, which vested on December 31, 2017 (representing 200% vesting of the originally reported amount) subject to final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ended on December 31, 2017 by Diamondback's compensation committee, and (ii) 12,022 performance-based restricted stock units awarded to Mr. Pantermuehl on January 19, 2016, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2018. Also excludes 5,850 performance-based restricted stock units awarded to Mr. Pantermuehl on February 16, 2017, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ending on December 31, 2018, and (ii) 11,700 performance-based restricted stock units awarded to Mr. Pantermuehl on February 16, 2017, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending December 31, 2019.

(6) Excludes 1,300 restricted stock units, which will vest on February 16, 2019.

(7) Excludes 1,950 restricted stock units, which will vest on February 16, 2019. Also excludes 12,022 performance-based restricted stock units awarded to Mr. Holder on January 19, 2016, which vested on December 31, 2017 (representing 200% vesting of the originally reported amount) subject to final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ended on December 31, 2017 by Diamondback's compensation committee, and (ii) 3,006 performance-based restricted stock units awarded to Mr. Holder on January 19, 2016, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2018. Also excludes (i) 2,925 performance-based restricted stock units awarded to Mr. Holder on February 16, 2017, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ending on December 31, 2018, and (ii) 5,850 performance-based restricted stock units awarded to Mr. Holder on February 16, 2017, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending December 31, 2019.

(8) Excludes 3,900 restricted stock units, which will vest on February 16, 2019. Also excludes 12,022 performance-based restricted stock units awarded to Mr.Molnar on January 19, 2016, which vested on December 31, 2017 (representing 200% vesting of the originally reported amount) subject to final determination upon certification of certain stockholder return performance conditions relative to Diamondback’s peer group during the two-year performance period ended on December 31, 2017 by Diamondback’s compensation committee, and (ii) 6,011 performance-based restricted stock units awarded to Mr. Molnar on January 19, 2016, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback’s peer group during the three-year performance period ending on December 31, 2018. Also excludes (i) 5,850 performance-based restricted stock units awarded to Mr. Molnar on February 16, 2017, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback’s peer group during the two-year performance period ending on December 31, 2018, and (ii)11,700 performance-based restricted stock units awarded to Mr. Molnar on February 16, 2017, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback’s peer group during the three-year performance period ending December 31, 2019.

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(9) Excludes 453 restricted stock units, which will vest on July 1, 2018, and 2,055 shares of Diamondback common stock, which will vest on the earlier of the one-year anniversary of the date of grant and the date of the 2018 annual meeting of stockholders of Diamondback.

(10) All of these shares are held by MBH Investments, Ltd., which is managed by MBH Financial, LLC, its general partner. Mr. Hollis, his spouse and the Hollis 2014 Irrevocable Trust hold 100% of the membership interests in MBH Financial, LLC, of which Mr. Hollis is the manager. Excludes 4,550 restricted stock units, which will vest on February 16, 2019. Also excludes 60,112 performance-based restricted stock units awarded to Mr. Hollis on January 19, 2016, which vested on December 31, 2017 (representing 200% vesting of the originally reported amount) subject to final determination upon certification of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance periods ending on December 31, 2017 by Diamondback's compensation committee, and (ii) 15,028 performance-based restricted stock units awarded to Mr. Hollis on January 19, 2016, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending on December 31, 2018. Also excludes (i) 6,825 performance-based restricted stock units awarded to Mr. Hollis on February 16, 2017, which are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the two-year performance period ending on December 31, 2018, and (ii) 13,650 performance-based restricted stock units awarded to Mr. Hollis on February 16, 2017, which awards are subject to the satisfaction of certain stockholder return performance conditions relative to Diamondback's peer group during the three-year performance period ending December 31, 2019.

Securities Authorized For Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2017:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights[2]	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans not approved by security holders[1]			
Long Term Incentive Plan	113,039	$ 18.48	8,957,317

(1) Our general partner adopted the LTIP in connection with the IPO in June 2014.
(2) Reflects the weighted average exercise price for each of the 7,600 outstanding unit options.

Changes in Control

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.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Agreements and Transactions with Affiliates

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

Payments to our General Partner and its Affiliates

Under the terms of our partnership agreement, we are required 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 the general partner in connection with operating our business. The partnership agreement does not set a limit on the amount of expenses for which the 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. For the year ended December 31, 2017, the General Partner received $2.5 million in reimbursements from the Partnership.

Distributions paid to Diamondback

Diamondback is entitled to receive its pro rata portion of the distributions we make in respect of our common units. During the year ended December 31, 2017, Diamondback received such distributions in the aggregate amount of $89.5 million.

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 filed a registration statement on Form S-3 registering, under the Securities Act, the common units issued to Diamondback for resale. 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.

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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 agreed to provide us and our general partner with general financial and strategic advisory services related to our business in return for an annual fee of $0.5 million, plus reimbursement of reasonable out-of-pocket expenses. This agreement had a term of two years commencing on the completion of the IPO, and continues 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 addition, under this agreement, we agreed to pay Wexford to-be-negotiated market-based fees approved by the conflicts committee of the board of directors of our general partner, if, and to the extent, we request such services from Wexford in connection with acquisitions and divestitures, financings or other transactions in which we may be involved. We agreed to indemnify Wexford and its affiliates from their 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. For the years ended December 31, 2017 and 2016, we did not pay any amounts under the advisory services 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. During the year ended December 31, 2017, we did not reimburse Diamondback under the tax sharing agreement.

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.

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.

Director Independence

The information required by Item 407(a) of Regulation S-K is included in “Item 10. Directors, Executive Officers and Corporate Governance” above.

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ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The audit committee of the board of directors of our general partner selected Grant Thornton LLP, an independent registered public accounting firm, to audit our consolidated financial statements for the years ended December 31, 2017, 2016 and 2015. The audit committee’s charter requires the audit committee to approve in advance all audit and non-audit services to be provided by our independent registered public accounting firm. All services reported in the audit, audit-related, tax and all other fees categories below with respect to our annual reports for the years ended December 31, 2017, 2016 and 2015 were approved by the audit committee.

The following table summarizes the aggregate Grant Thornton LLP fees that were allocated to us for independent auditing, tax and related services:

	Year Ended December 31,		
	2017	2016	2015
	(in thousands)		
Audit fees(1)	$138	$116	$97
Audit-related fees(2)	—	—	—
Tax fees(3)	—	—	—
All other fees(4)	—	—	—
Total	$138	$116	$97

(1) Audit fees represent amounts billed for each of the periods presented for professional services rendered in connection with those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters.

(2) Audit-related fees represent amounts billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews.

(3) Tax fees represent amounts billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice, and tax planning.

(4) All other fees represent amounts billed in each of the years presented for services not classifiable under the other categories listed in the table above.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents included in this report:

1. Financial Statements

Report of Independent Registered Public Accounting Firm	F-1
Consolidated Balance Sheets	F-2
Consolidated Statements of Operations	F-3
Consolidated Statement of Unitholders' Equity	F-4
Consolidated Statements of Cash Flows	F-5
Notes to Consolidated Financial Statements	F-6

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Partnership's consolidated financial statements and related notes.

3. Exhibits

Exhibit Number	Description
2.1*#	Purchase Agreement, dated as of November 21, 2017, among Viper Energy Partners LLC, DGK ORRI Company, L.P., as seller, and Royalty Resources L.P., as seller's parent guarantor.
3.1	Certificate of Limited Partnership of Viper Energy Partners LP (incorporated by reference to Exhibit 3.1 of the Partnership's Registration Statement on Form S-1 (File No. 333-195769) filed on May 7, 2014).
3.2	First Amended and Restated Agreement of Limited Partnership of Viper Energy Partners LP (incorporated by reference to Exhibit 3.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
4.1	Registration Rights Agreement, dated June 23, 2014, by and among Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 4.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.1	Senior Secured Revolving Credit Agreement, dated as of July 8, 2014, among Viper Energy Partners LP, as borrower, Wells Fargo Bank, National Association, as the administrative agent, sole book runner and lead arranger, and certain lenders from time to time party thereto. (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on July 14, 2014).
10.2	First Amendment, dated as of August 15, 2014, to Credit Agreement, dated as of July 8, 2014, among Viper Energy Partners LP, as borrower, the guarantors party thereto, Wells Fargo, National Association, as administrative agent, and certain lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Form 10-Q (File No. 001-36505) filed on August 10, 2015).
10.3	Second Amendment, dated as of May 22, 2015, to Credit Agreement, dated as of July 8, 2014, among Viper Energy Partners LP, as borrower, the guarantors party thereto, Wells Fargo, National Association, as administrative agent, and certain lenders party thereto (incorporated by reference to Exhibit 10.2 of the Partnership's Form 10-Q (File No. 001-36505) filed on August 10, 2015).
10.4	Third Amendment, dated as of June 21, 2016, to the Credit Agreement, dated as of July 8, 2014, by and among Viper Energy Partners LP, as borrower, Viper Energy Partners LLC, as guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 27, 2016).
10.5	Fourth Amendment, dated as of October 28, 2016, to the Credit Agreement, dated as of July 8, 2014, by and among Viper Energy Partners LP, as borrower, Viper Energy Partners LLC, as guarantor, Wells Fargo

	Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on November 3, 2016).
10.6	Fifth Amendment, dated as of November 28, 2017, to the Credit Agreement, dated as of July 8, 2014, by and among Viper Energy Partners LP, as borrower, Viper Energy Partners LLC, as guarantor, Wells Fargo Bank National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on December 4, 2017).

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3. Exhibits

10.7	Contribution Agreement, dated June 17, 2014, by and among Viper Energy Partners LLC, Viper Energy Partners GP LLC, Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.8+	Viper Energy Partners LP Long Term Incentive Plan (incorporated by reference to Exhibit 10.2 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.9	Advisory Services Agreement, dated June 23, 2014, by and among Viper Energy Partners LP, Viper Energy Partners GP LLC and Wexford Capital LP (incorporated by reference to Exhibit 10.3 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.1	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.4 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.11	Tax Sharing Agreement, dated June 23, 2014, by and between Viper Energy Partners LP and Diamondback Energy, Inc. (incorporated by reference to Exhibit 10.5 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.12+	Form of Unit Option Agreement (incorporated by reference to Exhibit 10.6 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on June 23, 2014).
10.13+	Form of Phantom Unit Agreement (incorporated by reference to Exhibit 10.2 of the Partnership's Quarterly Report on Form 10-Q (File No. 001-36505) filed on November 6, 2014).
21.1*	List of Subsidiaries of Viper Energy Partners LP.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, LP.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1++	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
99.1*	Reserve Report of Ryder Scott Company, L.P.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

*	Filed herewith.
#	The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission.
+	Management contract, compensatory plan or arrangement.
++	The certifications attached as Exhibit 32.1 accompany this Annual Report on Form 10-K pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed "filed" by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

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SIGNATURES

Pursuant to the requirements of the Securities and Exchange Act of 1934, the Registrant has duly caused this Annual Report to be signed on its behalf by the undersigned thereunto duly authorized.

	VIPER ENERGY PARTNERS LP	
Date: February 7, 2018		
	By:	VIPER ENERGY PARTNERS GP LLC its general partner
	By:	/s/ Travis D. Stice
	Name:	Travis D. Stice
	Title:	Chief Executive Officer

Pursuant to the requirements of the Securities and Exchange Act of 1934, this Annual Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer and Director (Principal Executive Officer)	February 7, 2018
/s/ Teresa L. Dick Teresa L. Dick	Chief Financial Officer (Principal Financial and Accounting Officer)	February 7, 2018
/s/ Steven E. West Steven E. West	Director	February 7, 2018
/s/ W. Wesley Perry W. Wesley Perry	Director	February 7, 2018
/s/ Spencer D. Armour Spencer D. Armour	Director	February 7, 2018
/s/ Michael L. Hollis Michael L. Hollis	Director	February 7, 2018
/s/ James L. Rubin James L. Rubin	Director	February 7, 2018
/s/ Rosalind Redfern Grover Rosalind Redfern Grover	Director	February 7, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Partners
Viper Energy Partners LP

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Viper Energy Partners LP (a Delaware limited partnership) and subsidiary (collectively, the “Partnership”) as of December 31, 2017 and 2016, the related consolidated statements of operations, unitholders’ equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the Partnership’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting 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.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ GRANT THORNTON LLP

We have served as the Partnership’s auditor since 2013.

Oklahoma City, Oklahoma
February 7, 2018

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Viper Energy Partners LP
Consolidated Balance Sheets

	December 31, 2017	December 31, 2016
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$24,197	$9,213
Restricted cash	—	500
Royalty income receivable	25,754	10,043
Royalty income receivable—related party	5,142	3,470
Other current assets	355	187
Total current assets	55,448	23,413
Property and equipment:		
Oil and natural gas interests, full cost method of accounting ($514,724 and $252,232 excluded from depletion at December 31, 2017 and 2016, respectively)	1,103,897	760,818
Accumulated depletion and impairment	(189,466)	(148,948)
Oil and natural gas interests, net	914,431	611,870
Funds held in escrow	6,304	—
Other assets	36,854	35,266
Total assets	$1,013,037	$670,549
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable	$2,960	$1,780
Other accrued liabilities	2,669	371
Total current liabilities	5,629	2,151
Long-term debt	93,500	120,500
Total liabilities	99,129	122,651
Commitments and contingencies (Note 10)		
Unitholders' equity:		
Common units (113,882,045 units issued and outstanding as of December 31, 2017 and 87,800,356 units issued and outstanding as of December 31, 2016)	913,908	547,898
Total unitholders' equity	913,908	547,898
Total liabilities and unitholders' equity	$1,013,037	$670,549

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Operations

	Year Ended December 31,		
	2017	2016	2015
	(In thousands, except per unit amounts)		
Operating income:			
Royalty income	$160,163	$78,837	$74,859
Lease bonus	11,870	309	—
Total operating income	172,033	79,146	74,859
Costs and expenses:			
Production and ad valorem taxes	10,608	5,544	5,531
Gathering and transportation	789	415	259
Depletion	40,519	29,820	35,436
Impairment	—	47,469	3,423
General and administrative expenses	6,296	5,209	5,835
Total costs and expenses	58,212	88,457	50,484
Income (loss) from operations	113,821	(9,311)	24,375
Other income (expense):			
Interest expense, net	(3,164)	(2,455)	(1,110)
Other income, net	821	867	1,154
Total other income (expense), net	(2,343)	(1,588)	44
Net income (loss)	$111,478	$(10,899)	$24,419
Net income (loss) attributable to common limited partners per unit:			
Basic and Diluted	$1.07	$(0.13)	$0.31
Weighted average number of limited partner units outstanding:			
Basic	104,318	83,081	79,717
Diluted	104,383	83,081	79,727

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Statement of Consolidated Unitholders’ Equity

	Limited Partners	
	Common Units	Amount
	(In thousands)	
Balance at December 31, 2014	79,709	$535,351
Unit-based compensation	17	3,929
Distribution to public		(7,968)
Distribution to Diamondback		(60,587)
Net income		24,419
Balance at December 31, 2015	79,726	$495,144
Net proceeds from the issuance of common units - public	6,050	93,462
Net proceeds from the issuance of common units - Diamondback	2,000	31,200
Unit-based compensation	24	3,815
Distributions to public		(9,574)
Distributions to Diamondback		(55,250)
Net loss		(10,899)
Balance at December 31, 2016	87,800	$547,898
Net proceeds from the issuance of common units - public	25,175	369,896
Net proceeds from the issuance of common units - Diamondback	700	10,067
Common units issued for acquisition	175	3,050
Unit-based compensation	32	2,395
Distributions to public		(41,367)
Distributions to Diamondback		(89,509)
Net income		111,478
Balance at December 31, 2017	113,882	$913,908

See accompanying notes to consolidated financial statements.

Table of Contents
Viper Energy Partners LP
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$111,478	$(10,899)	$24,419
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion	40,519	29,820	35,436
Impairment	—	47,469	3,423
Amortization of debt issuance costs	589	401	314
Non-cash unit-based compensation	2,395	3,815	3,929
Changes in operating assets and liabilities:			
Restricted cash	500	—	—
Royalty income receivable	(15,711)	(4,144)	(1,130)
Royalty income receivable—related party	(1,672)	—	—
Accounts payable—related party	—	(4)	4
Accounts payable and other accrued liabilities	1,298	1,945	(1,968)
Other current assets	(177)	224	(595)
Net cash provided by operating activities	139,219	68,627	63,832
Cash flows from investing activities:			
Acquisition of mineral interests	(344,079)	(205,721)	(43,907)
Net cash used in investing activities	(344,079)	(205,721)	(43,907)
Cash flows from financing activities:			
Proceeds from borrowings under credit facility	278,500	164,000	34,500
Repayment on credit facility	(305,500)	(78,000)	—
Debt issuance costs	(2,259)	(442)	(441)
Proceeds from public offerings	380,412	125,580	—
Public offering costs	(433)	(546)	—
Distributions to partners	(130,876)	(64,824)	(68,555)
Net cash provided by (used in) financing activities	219,844	145,768	(34,496)
Net increase (decrease) in cash	14,984	8,674	(14,571)
Cash and cash equivalents at beginning of period	9,213	539	15,110
Cash and cash equivalents at end of period	$24,197	$9,213	$539
Supplemental disclosure of cash flow information:			
Interest paid	$2,589	$1,953	$745

See accompanying notes to consolidated financial statements.

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 Select Market under the symbol “VNOM”. The Partnership was formed by Diamondback Energy, Inc. (“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 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”).

As of December 31, 2017, a wholly-owned subsidiary of Diamondback, Viper Energy Partners GP LLC (the “General Partner”), held a 100% non-economic general partner interest in the Partnership and Diamondback had an approximate 64% limited partner interest in the Partnership. Diamondback owns and controls the General Partner.

Basis of Presentation

The accompanying consolidated financial statements and related notes thereto were prepared in conformity with accounting principles generally accepted in the United States (“GAAP”). 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 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, but are not limited to, 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, the recoverability of costs of unevaluated properties and unit–based compensation.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and include all highly liquid investments purchased with a maturity of three months or less and money market funds. The Partnership maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Partnership has not experienced any significant losses from such investments.

Restricted Cash

In 2014, the Predecessor entered into an agreement to purchase certain overriding royalty interests and deposited $0.5 million in escrow. The Predecessor subsequently terminated the agreement and requested a return of the deposit. The seller challenged the termination and the escrow agent tendered the deposit to the court subject to a judicial determination of the proper payment of the funds. The parties reached a settlement of this matter in April 2017 and the funds were distributed in accordance with the terms of the settlement. Pending such distribution, these funds were classified as restricted cash.

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 the Partnership’s 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 the Partnership believes collection is doubtful. Royalty income receivable outstanding longer than the contractual payment terms are considered past due. The Partnership determines any allowance by considering a number of factors, including the length of time royalty income receivable are past due, the Partnership’s 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. The Partnership writes off specific royalty income receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. The Partnership determined that an allowance was unnecessary at both December 31, 2017 and 2016.

Fair Value of Financial Instruments

Our financial instruments consist of cash and cash equivalents, receivables, payables and a credit agreement. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of the instruments.

Oil and Natural Gas Properties

The Partnership uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Internal costs capitalized to the full cost pool represent management’s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas. At December 31, 2017 and 2016, 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 $10.07, $12.67 and $17.88 for the years ended December 31, 2017, 2016 and 2015, respectively. Depletion for oil and gas properties was $40.5 million, $29.8 million and $35.4 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Under the full cost method of accounting, the Partnership is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized. If the net book value exceeds the ceiling, an impairment or non-cash writedown is required. During the years ended December 31, 2016 and 2015, the Partnership recorded impairments on proved oil and natural gas properties of $47.5 million and $3.4 million, respectively. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2017.

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.

Debt Issuance Costs

Other assets include capitalized costs of $4.4 million, $2.2 million and $1.7 million, net of accumulated amortization of $1.4 million, $0.8 million and $0.4 million as of December 31, 2017, 2016 and 2015, respectively. The costs are associated with the Partnership's credit agreement and are being amortized over the term of the credit agreement.

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 the Partnership's royalty interest revenues in producing oil and natural gas properties and receivables with several significant purchasers. For the year ended December 31, 2017, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (US) Company ("Shell Trading") (47%) and RSP Permian LLC (23%). For the year ended December 31, 2016, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (57%) and RSP Permian LLC (32%). For the year ended December 31, 2015, two purchasers each accounted for more than 10% of royalty interest revenue: Shell Trading (68%) and RSP Permian LLC (25%). The Partnership does not require collateral and does not believe the loss of any single purchaser would materially impact the Partnership's operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Investments

The Partnership has an equity interest in a limited partnership that is so minor that the Partnership has no influence over partnership operating and financial policies. This interest was acquired during the year ended December 31, 2014 and is accounted for under the cost method. Under the cost method, investments are carried at cost and are adjusted only for other than temporary declines in fair value, certain distributions and additional investments. As of December 31, 2017, the book value of this investment was $33.9 million, which is included in other assets in the accompanying consolidated balance sheets.

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 7—Unit–Based Compensation.

Income Taxes

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

The Partnership is subject to the Texas margin tax. Diamondback does not expect any Texas margin tax to be due for the years ended December 31, 2017, 2016 and 2015, so no amount has been provided in the accompanying financial statements.

New Accounting Pronouncements

Recently Issued Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers.

The Partnership will adopt this Accounting Standards Update effective January 1, 2018 using the modified retrospective approach. The Partnership has reviewed various contracts that represent its material revenue streams and determined that there will be no impact to its financial position, results of operations or liquidity. Upon adoption of this Accounting Standards Update, the Partnership will not be required to record a cumulative effect adjustment due to the new Accounting Standards Update not having a quantitative impact compared to existing GAAP. Also, upon adoption of this Accounting Standards Update, the Partnership will not be required to alter its existing information technology and internal controls outside of ongoing contract review processes in order to identify impacts of future revenue contracts entered into by the Partnership. The Partnership does not anticipate the disclosure requirements under the Accounting Standards Update to have a material change on how it presents information regarding its revenue streams as compared to existing GAAP.

In January 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-01, "Financial Instruments–Overall". This update applies to any entity that holds financial assets or owes financial liabilities. This update requires equity investments (except for those accounted for under the equity method or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. The Partnership will adopt this standard effective January 1, 2018 by means of a cumulative-effect adjustment which will decrease Unitholders' Equity and will bring the fair value of its investment to $15.2 million or $15.20 per unit for that investment.

In November 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-18, "Statement of Cash Flows - Restricted Cash". This update affects entities that have restricted cash or restricted cash equivalents. The Partnership will adopt this update retrospectively effective January 1, 2018. The adoption of this update will only effect the presentation on the Statement of Cash Flows.

In January 2017, the Financial Accounting Standards Board issued Accounting Standards Update 2017-01, "Business Combinations - Clarifying the Definition of a Business". This update apples to all entities that must determine whether they acquired or sold a business. This update provides a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. The Partnership will adopt this update prospectively effective January 1, 2018. The adoption of this update will not have an impact on its financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, “Leases”. This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. As of the filing date, the Partnership was not the lessor or lessee of any leases other than mineral leases which were excluded from the scope of this Accounting Standards Update. Therefore, the Partnership believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity.

In June 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-13, “Financial Instruments - Credit Losses”. This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Partnership does not believe the adoption of this standard will have an impact on its financial statements since it does not have a history of credit losses.

3. ACQUISITIONS

2017 Activity

During the year ended December 31, 2017, the Partnership acquired mineral interests underlying 3,157 net royalty acres for an aggregate of approximately $343.1 million and, as of December 31, 2017, had mineral interests underlying 9,570 net royalty acres. The Partnership funded these acquisitions primarily with borrowings under its revolving credit facility, with a portion of the net proceeds from its January and July 2017 offerings of common units and with the issuance of 174,513 common units to a seller in a private placement in May 2017.

2016 Activity

During the year ended December 31, 2016, the Partnership acquired mineral interests underlying 2,142 net royalty acres in 63 transactions for an aggregate of approximately $205.7 million. The Partnership funded these acquisitions primarily with borrowings under its revolving credit facility and a portion of the net proceeds from its August 2016 offering of common units.

2015 Activity

During the year ended December 31, 2015, the Partnership acquired an approximate average 1.5% overriding royalty interest in certain acreage primarily located in Howard County, Texas from Diamondback for $31.1 million. This acquisition was primarily funded with borrowings under the Partnership's credit agreement discussed in Note 5.

4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	December 31,	
	2017	2016
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$589,173	$508,586
Not subject to depletion	514,724	252,232
Gross oil and natural gas interests	1,103,897	760,818
Accumulated depletion and impairment	(189,466)	(148,948)
Oil and natural gas interests, net	$914,431	$611,870

Balance of costs not subject to depletion:	
Incurred in 2017	$284,471
Incurred in 2016	158,156

Incurred in 2015	30,896
Incurred in 2014	41,201
Total not subject to depletion	$514,724

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 the Partnership's unevaluated costs into the amortization base is expected to be completed within three to five years.

Under the full cost method of accounting, the Partnership is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas interests. Net capitalized costs are limited to the lower of unamortized cost or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Partnership's oil and natural gas revenue, (b) the cost of interests not being amortized, if any, and (c) the lower of cost or market value of unproved interests included in the cost being amortized. If the net book value exceeds the ceiling, an impairment or non-cash write down is required.

As a result of the decline in prices, the Partnership recorded non-cash impairments for the years ended December 31, 2016 and 2015 of $47.5 million and $3.4 million, respectively, which are included in accumulated depletion and impairment. There was no impairment recorded for the year ended December 31, 2017. For 2016 and 2015, the impairment charges affected the Partnership's reported net loss but did not reduce its cash flow. In addition to commodity prices, the Partnership's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test limitations and impairment analysis in future periods.

5. DEBT

Credit Agreement-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as administrative agent, and Wells Fargo Securities, as sole book runner and lead arranger. The credit agreement, as amended, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on its oil and natural gas reserves and other factors (the "borrowing base") of $400.0 million, subject to scheduled semi-annual and other elective borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of December 31, 2017, the borrowing base was set at $400.0 million, and the Partnership had $93.5 million of outstanding borrowings and $306.5 million available for future borrowings under its revolving credit facility.

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 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternative base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and 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 commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022. The loan is secured by substantially all of our and our subsidiary's 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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $400.0 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.

As of December 31, 2017, the Partnership was in compliance with all financial covenants under its credit agreement. 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. With certain specified exceptions, the terms and provisions of the Partnership's credit agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

6. RELATED PARTY TRANSACTIONS

Acquisition

During the year ended December 31, 2015, the Partnership acquired an approximate average 1.5% overriding royalty interest in certain acreage primarily located in Howard County, Texas from Diamondback for $31.1 million. This acquisition was primarily funded with borrowings under the Partnership's credit agreement discussed in Note 5.

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 dated June 23, 2014 (the "Partnership Agreement"). The Partnership Agreement requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership's behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership's business. The Partnership Agreement does not set a limit on the amount of expenses for which the 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 the Partnership or on the Partnership's behalf and expenses allocated to the General Partner by its affiliates. The General Partner is entitled to determine the expenses that are allocable to the Partnership. For the year ended December 31, 2017, the General Partner received from the Partnership reimbursements of $2.5 million. For the year ended December 31, 2016, the General Partner did not receive any reimbursements from the Partnership. For the year ended December 31, 2015, the General Partner did not receive any reimbursements from the Partnership other than the $4,000 outstanding at December 31, 2014.

Advisory Services Agreement

In connection with the closing of the IPO, the Partnership and General Partner entered into an advisory services agreement with Wexford Capital LP ("Wexford") dated as of June 23, 2014 (the "Advisory Services Agreement"), under which Wexford agreed to provide the Partnership and the General Partner with general financial and strategic advisory services related to the Partnership's business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement had an initial term of two years commencing on June 23, 2014, and continues 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 the Partnership terminates the Advisory Services Agreement, the Partnership is obligated to pay all amounts due through the remaining term. In addition, the Partnership agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of the General Partner, if, and to the extent, the Partnership requests services from Wexford in connection with acquisitions and divestitures, financings or other transactions in which the Partnership may be involved. The services provided by Wexford under the Advisory

Services Agreement do not extend to the Partnership’s day-to-day business or operations. The Partnership has agreed to indemnify Wexford and its affiliates from their 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. For the years ended December 31, 2017 and 2016, the Partnership did not pay any amounts under the Advisory Services Agreement. For the year ended December 31, 2015, the Partnership paid $0.5 million under the Advisory Services Agreement.

Tax Sharing

In connection with the closing of the IPO, the Partnership entered into a tax sharing agreement with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to reimburse Diamondback for its share of state and local income and other taxes for which the Partnership’s 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 the Partnership may be a member for this purpose, to owe less or no tax. In such a situation, the Partnership agreed to reimburse Diamondback for the tax the Partnership would have owed had the tax attributes not been available or used for the Partnership's benefit, even though Diamondback had no cash tax expense for that period.

Lease Bonus

During the year ended December 31, 2017, Diamondback paid the Partnership $0.1 million in lease bonus payments to extend the term of two leases, reflecting an average bonus of $7,459 per acre. During the year ended December 31, 2016, Diamondback paid the Partnership $0.3 million in lease bonus payments to extend the term of six leases, reflecting an average bonus of $1,371 per acre.

7. UNIT–BASED COMPENSATION

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 9,070,356 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 years ended December 31, 2017, 2016 and 2015, the Partnership incurred $2.4 million, $3.8 million and $3.9 million, 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, the Partnership granted 2,500,000 unit options to the executive officers of the General Partner. The unit options vested approximately 33% ratably on each of the first three anniversaries of the date of grant. All outstanding unit options were amended effective November 29, 2016 to provide that vested unit options became exercisable upon the earlier to occur of (i) the "Exercise Window Period" beginning on the third anniversary of the date of grant and ending on December 31, 2017, or (ii) the "Change of Control Exercise Period" beginning ten days before and ending on the date a change of control occurs (the earlier occurring of such events, the "Exercise Period"). At any time within the Exercise Period, if a participant attempted to exercise a vested unit option and the fair market value per unit as of such date was less than the exercise price per option unit, the vested unit option would not be exercisable. As of December 31, 2017, all vested unit options automatically terminated and became null and void.

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

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Notes to Financial Statements - (Continued)

The following table presents the unit option activity under the LTIP for the year ended December 31, 2017:

	Unit Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Intrinsic Value
			(in years)	(in thousands)
Outstanding at December 31, 2016	2,424,266	$26.00		
Expired/Forfeited	(2,416,666)	$26.00		
Outstanding at December 31, 2017	7,600	$18.49	0.00	$ —
Vested and Expected to Vest at December 31, 2017	7,600	$18.49	0.00	$ —

Phantom Units

Under the LTIP, the board of directors of the General Partner is authorized to issue phantom units to eligible employees. The Partnership estimates the fair value of phantom units as the closing price of the Partnership's common units on the grant date of the award, which is expensed over the applicable vesting period. Upon vesting the phantom units entitle the recipient to one common unit of the Partnership for each phantom unit.

The following table presents the phantom unit activity under the LTIP for the year ended December 31, 2017:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2016	21,048	$ 16.23
Granted	116,567	$ 17.09
Vested	(32,176)	$ 16.49
Unvested at December 31, 2017	105,439	$ 17.10

The aggregate fair value of phantom units that vested during the year ended December 31, 2017 was $0.5 million. As of December 31, 2017, the unrecognized compensation cost related to unvested phantom units was $1.3 million. Such cost is expected to be recognized over a weighted-average period of 1.4 years.

8. PARTNERS' CAPITAL 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 December 31, 2017, the Partnership had a total of 113,882,045 common units issued and outstanding, of which 73,150,000 common units were owned by Diamondback, representing approximately 64% of the total Partnership units outstanding.

The following table summarizes changes in the number of the Partnership's common units:

	Common Units
Balance at December 31, 2016	87,800,356

Common units issued in public offerings	25,875,000
Common units vested and issued under the LTIP	32,176
Common units issued for acquisition	174,513
Balance at December 31, 2017	113,882,045

The board of directors of the 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. Cash distributions are 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 is determined by the board of directors of our general partner following the end of such quarter. Available cash for each quarter generally equals 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.

The following table presents cash distributions approved by the board of directors of the General Partner for the periods presented.

Declaration Date	Quarter	Amount per Common Unit	Payment Date	Amount Distributed to Diamondback
				(in thousands)
February 5, 2015	Q4 2014	$ 0.250	February 27, 2015	$ 17,612
May 1, 2015	Q1 2015	$ 0.189	May 22, 2015	$ 13,385
July 31, 2015	Q2 2015	$ 0.220	August 21, 2015	$ 15,499
October 30, 2015	Q3 2015	$ 0.200	November 20, 2015	$ 14,091
February 12, 2016	Q4 2015	$ 0.228	February 26, 2016	$ 16,063
May 2, 2016	Q1 2016	$ 0.149	May 23, 2016	$ 10,497
July 21, 2016	Q2 2016	$ 0.189	August 22, 2016	$ 13,693
October 25, 2016	Q3 2016	$ 0.207	November 18, 2016	$ 14,997
February 3, 2017	Q4 2016	$ 0.258	February 24, 2017	$ 18,692
April 28, 2017	Q1 2017	$ 0.302	May 25, 2017	$ 21,880
July 28, 2017	Q2 2017	$ 0.332	August 24, 2017	$ 24,286
October 16, 2017	Q3 2017	$ 0.337	November 14, 2017	$ 24,652

9. EARNINGS PER UNIT

The net income per common unit on the consolidated statements of operations is based on the net income (loss) of the Partnership for the years ended December 31, 2017, 2016 and 2015, since this is the amount of net income that is attributable to the Partnership’s common units.

The Partnership’s net income (loss) is allocated wholly to the common units as the General Partner does not have an economic interest. Payments made to the Partnership’s unitholders are determined in relation to the cash distribution policy described in Note 8—Partners’ Capital and Partnership Distributions.

Basic net income per common unit is calculated by dividing net income (loss) by the weighted-average number of common units outstanding during the period. Diluted net income per common unit gives effect, when applicable, to unvested common units granted under the LTIP.

	Year Ended December 31,		
	2017	2016	2015
	(In thousands, except per unit amounts)		
Net income (loss) attributable to the period	111,478	(10,899)	24,419
Weighted average common units outstanding			
Basic weighted average common units outstanding	104,318	83,081	79,717

Effect of dilutive securities:			
Potential common units issuable	65	—	10
Diluted weighted average common units outstanding	104,383	83,081	79,727
Net income (loss) per common unit, basic	$1.07	$(0.13)	$0.31
Net income (loss) per common unit, diluted	$1.07	$(0.13)	$0.31

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For the years ended December 31, 2017, 2016 and 2015, there were 39,788 units, 1,567,155 units and 1,697,142 units, respectively, that were not included in the computation of diluted earnings per unit because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per unit in future periods.

10. 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.

11. SUBSEQUENT EVENTS

Cash Distribution

On January 31, 2018, the board of directors of the General Partner approved a cash distribution for the fourth quarter of 2017 of $0.46 per common unit, payable on February 26, 2018, to unitholders of record at the close of business on February 19, 2018.

Recent Acquisitions

Since the end of the fourth quarter of 2017, the Partnership acquired from unrelated third party sellers additional mineral interests underlying 137,443 gross acres, 1,617 net acres and 900 net royalty acres in the Permian Basin and Eagle Ford Shale for an aggregate of approximately $149.4 million, subject to post-closing adjustments. As a result, as of February 2, 2018, the Partnership’s assets included mineral interests underlying 385,046 gross acres, 45,460 net acres and 10,470 net royalty acres primarily in the Permian Basin and Eagle Ford Shale. These acquisitions were primarily funded with cash on hand and borrowings under the Partnership’s revolving credit facility.

12. 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,	
	2017	2016
	(In thousands)	
Oil and natural gas interests:		
Proved	$589,173	$508,586
Unproved	514,724	252,232
Total oil and natural gas interests	1,103,897	760,818

Accumulated depletion and impairment	(189,466)	(148,948)
Net oil and natural gas interests capitalized	$914,431	$611,870

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Costs incurred in oil and natural gas activities

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

	December 31,		
	2017	2016	2015
	(In thousands)		
Acquisition costs			
Proved properties	$55,948	$31,441	$4,121
Unproved properties	287,131	174,385	39,786
Total	$343,079	$205,826	$43,907

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 the Partnership's oil, natural gas and natural gas liquids operations.

	December 31,		
	2017	2016	2015
	(In thousands)		
Royalty income	$160,163	$78,837	$74,859
Production and ad valorem taxes	(10,608)	(5,544)	(5,531)
Gathering and transportation	(789)	(415)	(259)
Depletion	(40,519)	(29,820)	(35,436)
Impairment	—	(47,469)	(3,423)
Results of operations from oil, natural gas and natural gas liquids	$108,247	$(4,411)	$30,210

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2017, 2016 and 2015 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.

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The changes in estimated proved reserves are as follows:

	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
	(In thousands)		
Proved Developed and Undeveloped Reserves:			
As of December 31, 2014	12,830	2,514	18,994
Purchase of reserves in place	107	3	431
Extensions and discoveries	8,450	2,013	9,476
Revisions of previous estimates	(1,454)	(375)	(3,465)
Production	(1,555)	(239)	(1,128)
As of December 31, 2015	18,378	3,916	24,308
Purchase of reserves in place	1,138	437	2,315
Extensions and discoveries	5,647	1,477	7,181
Revisions of previous estimates	(2,041)	74	(5,223)
Production	(1,778)	(328)	(1,490)
As of December 31, 2016	21,344	5,576	27,091
Purchase of reserves in place	2,106	252	5,245
Extensions and discoveries	7,859	1,813	11,106
Revisions of previous estimates	(2,525)	(813)	(3,498)
Production	(2,899)	(533)	(3,549)
As of December 31, 2017	25,885	6,295	36,395
Proved Developed Reserves:			
December 31, 2015	9,700	2,205	13,739
December 31, 2016	12,332	3,247	15,933
December 31, 2017	18,788	4,536	29,256
Proved Undeveloped Reserves:			
December 31, 2015	8,677	1,711	10,569
December 31, 2016	9,012	2,329	11,158
December 31, 2017	7,097	1,759	7,139

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.

During the year ended December 31, 2017, the Partnership’s extensions and discoveries of 11,524 MBoe resulted primarily from the drilling of 96 new wells and from 40 new proved undeveloped locations added. The Partnership’s negative revisions of previous estimated quantities of 3,921 MBoe were primarily due to changes in type curves. The purchase of reserves in place of 3,232 MBoe were due to multiple acquisitions primarily located in Pecos, Reeves and Loving counties.

During the year ended December 31, 2016, the Partnership's extensions and discoveries of 7,125 MBoe resulted primarily from the drilling of 33 new wells and from 32 new proved undeveloped locations added. The Partnership's negative revisions of previous estimated quantities of 1,968 MBoe were primarily due to technical revisions with the remainder due to lower product pricing. The purchase of reserves in place of 1,575 MBoe were due to multiple acquisitions with the largest being located in Loving and Midland counties.

During the year ended December 31, 2015, purchases of reserves were primarily from one acquisition in Howard County and several minor acquisitions in other areas consisting of 124 vertical wells and one horizontal well. Extensions are primarily

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the result of horizontal development of the Wolfcamp B and Lower Spraberry shales. The extensions were the result of one vertical well and 83 horizontal wells, of which 51 horizontal wells are in the proved undeveloped category. Diamondback is the operator of 57 of the 84 total wells. Revisions are primarily the result of downgrading nine horizontal wells and 48 vertical wells that were classified as PUDs into the probable category as a result of lower product prices and subsequent changes in drilling plans such that the wells are no longer expected to be drilled within five years of when they were originally booked.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows are 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, 2017, 2016 and 2015.

	December 31,		
	2017	2016	2015
	(In thousands)		
Future cash inflows	$1,445,883	$948,090	$912,276
Future production taxes	(125,564)	(69,109)	(61,777)
Future state margin tax expenses	(6,932)	(4,615)	(4,789)
Future net cash flows	1,313,387	874,366	845,710
10% discount to reflect timing of cash flows	(688,039)	(461,785)	(449,947)
Standardized measure of discounted future net cash flows	$625,348	$412,581	$395,763

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,		
	2017	2016	2015
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$48.21	$39.64	$45.03
Natural gas (per Mcf)	$2.13	$1.36	$1.64
Natural gas liquids (per Bbl)	$19.15	$11.69	$11.41

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

	December 31, 2017	2016	2015
	(In thousands)		
Standardized measure of discounted future net cash flows at the beginning of the period	$412,581	$395,763	$553,236
Purchase of minerals in place	54,662	23,651	2,963
Sales of oil and natural gas, net of production costs	(149,555)	(74,628)	(69,328)
Extensions and discoveries	214,479	104,451	181,330
Net changes in prices and production costs	99,382	(42,155)	(269,154)
Revisions of previous quantity estimates	(50,773)	(42,883)	(71,399)
Net changes in state margin taxes	(1,129)	51	(1,884)
Accretion of discount	41,477	39,800	54,911
Net changes in timing of production and other	4,224	8,531	15,088
Standardized measure of discounted future net cash flows at the end of the period	$625,348	$412,581	$395,763

13. QUARTERLY FINANCIAL DATA (Unaudited)

	2017 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per unit amounts)			
Royalty income	$32,050	$35,933	$42,211	$49,969
Income from operations	21,450	22,479	27,067	42,825
Net income	20,652	22,149	26,607	42,070
Net income attributable to common limited partners per unit:				
Basic	$0.22	$0.23	$0.24	$0.37
Diluted	$0.22	$0.23	$0.24	$0.37

	2016 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per unit amounts)			
Royalty income	$14,086	$16,836	$19,992	$27,923
Income (loss) from operations	(23,104)	(13,711)	10,594	16,910
Net income (loss)	(23,335)	(14,020)	10,202	16,254
Net income (loss) attributable to common limited partners per unit:				
Basic	$(0.29)	$(0.18)	$0.12	$0.20
Diluted	$(0.29)	$(0.18)	$0.12	$0.20