Viper Energy Partners LP
Form 10-Q
August 10, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2015
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	79701
(Address of Principal Executive Offices)	(Zip Code)

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the past 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 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 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	o
Non-Accelerated Filer	ý	Smaller Reporting Company	o

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

As of August 5, 2015, 79,717,776 common limited partner units of the registrant were outstanding.

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GLOSSARY OF TERMS

The following includes a description of the meanings of some of the oil and natural gas industry terms used in this Quarterly Report on Form 10-Q (“Quarterly 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 Quarterly Report in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Bbls per day.

BOE. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.

BOE/d. BOE per day.

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

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

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

Delaware Act. Delaware Revised Uniform Limited Partnership Act.

Deterministic method. The method of estimating reserves or resources under which a single value for each parameter (from the geoscience, engineering or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres that are allocated or assignable to productive wells or wells capable of production.

Development costs. Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.

Development well. A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry hole or dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

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

Exploitation. A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory 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.

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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.
Inception. September 18, 2013.
MBbls. Thousand barrels of crude oil or other liquid hydrocarbons.
MBOE. One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
Mcf. Thousand cubic feet of natural gas.
Mcf/d. Mcf per day.
Mineral interests. The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu. Million British Thermal Units.
MMcf. Million cubic feet of natural gas.
Net acres or net wells. The sum of the fractional working interest owned in gross acres.
Net revenue interest. An owner’s interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
NYMEX. New York Mercantile Exchange.
Oil and natural gas properties. Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator. The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
PDP. Proved developed producing.
Play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
PUD. Proved undeveloped.
Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved developed reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

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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.
SEC. Securities and Exchange Commission.
Spacing. The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.
Standardized measure. The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Because we are a limited partnership, we are generally not subject to federal or state income taxes and thus make no provision for federal or state income taxes in the calculation of our standardized measure. Standardized measure does not give effect to derivative transactions.
Tight formation. A formation with low permeability that produces natural gas with very low flow rates for long periods of time.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Wellbore. The hole drilled by the bit that is equipped for oil or natural gas production on a completed well.
Working interest. An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.
WTI. West Texas Intermediate.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Quarterly 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 of 1933, as amended (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934, as amended (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 Quarterly Report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project,” and similar expressions are intended to ide forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this Quarterly Report, including those detailed under Part II. Item 1A. Risk Factors in this Quarterly 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 Quarterly Report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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Viper Energy Partners LP
Consolidated Balance Sheets
(Unaudited)

	June 30, 2015	December 31, 2014
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$9,988	$15,110
Restricted cash	500	500
Royalty income receivable	9,902	8,239
Other current assets	467	253
Total current assets	20,857	24,102
Oil and natural gas interests, based on the full cost method of accounting ($45,741 and $91,444 excluded from depletion at June 30, 2015 and December 31, 2014, respectively)	511,008	511,085
Accumulated depletion	(50,650)	(32,800)
	460,358	478,285
Other assets	35,175	35,015
Total assets	$516,390	$537,402
Liabilities and Unitholders' Equity/Members' Equity		
Current liabilities:		
Accounts payable	$—	$6
Other accrued liabilities	1,105	2,045
Total current liabilities	1,105	2,051
Commitments and contingencies (Note 10)		
Unitholders' equity:		
Common units (79,717,776 units issued and outstanding as of June 30, 2015 and December 31, 2014)	515,285	535,351
Total unitholders' equity	515,285	535,351
Total liabilities and unitholders' equity	$516,390	$537,402

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014*	2015	2014*
	(In thousands, except per unit amounts)			
Royalty income	19,619	17,249	$36,164	$33,102
Costs and expenses:				
Production and ad valorem taxes	1,417	1,392	2,745	2,313
Depletion	8,949	6,064	17,850	11,631
General and administrative expenses	1,168	219	2,595	285
General and administrative expenses—related party	139	78	264	156
Total costs and expenses	11,673	7,753	23,454	14,385
Income from operations	7,946	9,496	12,710	18,717
Other income (expense)				
Interest expense	(207)	—	(375)	—
Interest expense—related party, net of capitalized interest	—	(5,387)	—	(10,755)
Other income	306	—	792	—
Total other income (expense), net	99	(5,387)	417	(10,755)
Net income	8,045	4,109	$13,127	$7,962
Allocation of net income:				
Net income attributable for the period April 1, 2014 or January 1, 2014, as applicable, through June 22, 2014		3,168		$7,021
Net income attributable to the period June 23, 2014 through June 30, 2014		941		941
		4,109		$7,962
Net income attributable to common limited partners per unit:				
Basic and Diluted	$0.10	$0.01	$0.16	$0.01
Weighted average number of limited partner units outstanding				
Basic and Diluted	79,710	76,200	79,710	76,200

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

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Viper Energy Partners LP
Statement of Consolidated Unitholders' Equity and Members' Equity
(Unaudited)

	Limited Partners		
	Common	Predecessor Members' Equity	Total
	(In thousands)		
Balance at December 31, 2013	$—	$2,988	$2,988
Net income attributable to the period January 1, 2014 through June 22, 2014	—	7,021	7,021
Contribution of Note payable to Equity	—	437,115	437,115
Distribution payable to Diamondback (Note 1)	—	(11,260)	(11,260)
Exchange of Predecessor interests for units (Note 1)	435,864	(435,864)	—
Net proceeds from the issuance of common units	137,238	—	137,238
Distribution of net proceeds to Diamondback (Note 1)	(137,500)	—	(137,500)
Unit-based compensation	128	—	128
Net income attributable to the period June 23, 2014 through June 30, 2014	941	—	941
Balance at June 30, 2014*	$436,671	$—	$436,671
Balance at December 31, 2014	$535,351	$—	$535,351
Unit-based compensation	1,878	—	1,878
Distribution to public	(4,074)	—	(4,074)
Distribution to Diamondback	(30,997)	—	(30,997)
Net income	13,127	—	13,127
Balance at June 30, 2015	$515,285	$—	$515,285

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

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Viper Energy Partners LP
Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30,	
	2015	2014*
	(In thousands)	
Cash flows from operating activities:		
Net income	$13,127	$7,962
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion	17,850	11,631
Amortization of debt issuance costs	141	—
Non-cash unit-based compensation expense	1,878	128
Changes in operating assets and liabilities:		
Royalty income receivable	(1,663)	2,258
Other current assets	(214)	(16)
Accounts payable—related party	—	(9,172)
Accounts payable and other accrued liabilities	(946)	1,273
Net cash provided by operating activities	30,173	14,064
Cash flows from investing activities:		
Additions to oil and natural gas interests	—	(5,275)
Other	77	—
Net cash provided by (used in) investing activities	77	(5,275)
Cash flows from financing activities		
Principal payment on subordinated note	—	(2,885)
Debt issuance costs	(301)	—
Proceeds from public offerings	—	139,035
Public offering costs	—	(1,172)
Distribution of net proceeds from public offerings to Diamondback (Note 1)	—	(137,500)
Distribution to members	(35,071)	—
Net cash used in financing activities	(35,372)	(2,522)
Net increase (decrease) in cash	(5,122)	6,267
Cash at beginning of period	15,110	762
Cash and cash equivalents at end of period	$9,988	$7,029
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$234	$16,496
Supplemental disclosure of non—cash transactions:		
Note payable converted to equity	$—	$437,115
Capitalized interest	$—	$5,275

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Cash Flows
(Unaudited)

*See Note 1 for information regarding the basis of financial statement presentation.

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Viper Energy Partners LP
Notes to Financial Statements
(Unaudited)

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

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

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

In connection with the IPO, Diamondback contributed all of the membership interests in the Predecessor to the Partnership in exchange for 70,450,000 common units. Diamondback maintained its non-economic general partner interest in the Partnership through its wholly-owned subsidiary, Viper Energy Partners GP LLC (the “General Partner”), a Delaware limited liability company. In addition, in connection with the closing of the IPO, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.6 million and the net proceeds from the IPO. As of December 31, 2014, the Partnership had distributed $148.8 million to Diamondback as part of the IPO transactions. The contribution of the Predecessor to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. The common units were sold to the public at $28.50 per unit and the Partnership received net proceeds of approximately $94.8 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

As of June 30, 2015, the General Partner held a 100% non-economic general partner interest in the Partnership and Diamondback had an approximate 88% limited partner interest in the Partnership. Diamondback owns and controls the General Partner.

Basis of Presentation

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

The accompanying consolidated financial statements and related notes thereto were prepared in conformity with accounting principles 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 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.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, "Revenue from Contracts with Customers". ASU 2014-09 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 certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2016, with early application not permitted. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Partnership is currently evaluating the impact, if any, that the adoption of ASU 2014-09 will have on the Partnership's financial position, results of operations, and liquidity.

In April 2015, the FASB issued ASU 2015-03, "Interest—Imputation of Interest". ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from that debt liability, consistent with the presentation of a debt discount to simplify the presentation of debt issuance costs. The standard will be effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016. Early application will be permitted for financial statements that have not previously been issued. Adoption of the new guidance will only affect the presentation of the Partnership's consolidated balance sheets and will not have a material impact on the Partnership's consolidated financial statements.

3. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	June 30, 2015	December 31, 2014
	(in thousands)	
Oil and natural gas interests:		

Subject to depletion	$465,267	$419,641
Not subject to depletion—acquisition costs		
Incurred in 2014	45,733	48,266
Incurred in 2013	8	43,178
Total not subject to depletion	45,741	91,444
Gross oil and natural gas interests	511,008	511,085
Accumulated depletion	(50,650)	(32,800)
Oil and natural gas interests, net	$460,358	$478,285

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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.

4. DEBT

Credit Agreement-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo Bank, National Association, or Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. As of June 30, 2015, the borrowing base remained at $175.0 million. The Partnership had no outstanding borrowings as of June 30, 2015.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Partnership that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Partnership is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of July 8, 2019. The loan is secured by substantially all of the assets of the Partnership and its subsidiary.

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

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

EBITDAX is annualized for the four fiscal quarters ending on the last day of the fiscal quarter for which financial statements are available, beginning with the quarter ended September 30, 2014.

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

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

Subordinated Note

Effective September 19, 2013, the Predecessor issued a subordinated note to Diamondback for the principal sum of $440.0 million for a royalty interest acquisition. In connection with the IPO, the subordinated note was converted to equity. The note bore interest at 7.625% per annum. Interest was due and payable monthly in arrears on the first business day of each calendar month. The unpaid principal balance and all accrued interest on the note were due and payable in full on October 1, 2021. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under the

Diamondback credit agreement. Prior to the completion of the IPO, there was $437.1 million of principal and interest outstanding under this note.

5. RELATED PARTY TRANSACTIONS

Partnership Agreement

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

The Partnership Agreement requires 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.

Advisory Services Agreement

In connection with the closing of the IPO, the Partnership and General Partner entered into an advisory services agreement (the "Advisory Services Agreement") with Wexford Capital LP ("Wexford"), Diamondback's equity sponsor, dated as of June 23, 2014, under which Wexford provides 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 has 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 has agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of the General Partner for such services as may be provided by Wexford at the Partnership's request in connection with future 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 any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford's or its affiliates' gross negligence or willful misconduct. For the three months and six months ended June 30, 2015, we incurred costs of $0.1 million and $0.3 million, respectively, under the Advisory Services Agreement.

Tax Sharing

In connection with the closing of the IPO, the Partnership entered into a tax sharing agreement (the "Tax Sharing Agreement") with Diamondback pursuant to which the Partnership will 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 would 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.

Shared Services Agreement

Effective September 19, 2013, the Predecessor entered into a shared services agreement with Diamondback E&P LLC, a wholly-owned subsidiary of Diamondback. This agreement was terminated in connection with the IPO. Under this agreement, Diamondback E&P LLC provided consulting and administrative services to the Predecessor. The Predecessor incurred a monthly charge for the services of $26,000. For the three months and six months ended

June 30, 2014, the Partnership incurred costs under this agreement of $0.1 million and $0.2 million, respectively.

6. UNIT–BASED COMPENSATION

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

For the three months and six months ended June 30, 2015, the Partnership incurred $0.9 million and $1.9 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 vest approximately 33% ratably on each of the next three anniversaries of the date of grant. In the event the fair market value per unit as of the exercise date is less than the exercise price per option unit, the vested options will automatically terminate and become null and void as of the exercise date.

The fair value of the unit options on the date of grant is expensed over the applicable vesting period. 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	%

The following table presents the unit option activity under the LTIP for the six months ended June 30, 2015:

	Unit Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	2,500,000	$26.00		
Granted	—	$—		
Outstanding at June 30, 2015	2,500,000	$26.00	1.97	$—
	2,500,000	$26.00	1.97	$—

Vested and Expected to vest at June 30, 2015				
Exercisable at June 30, 2015	—	$—	—	$—

As of June 30, 2015, the unrecognized compensation cost related to unvested unit options was $6.9 million. Such cost is expected to be recognized over a weighted-average period of 2.0 years.

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 values 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 unit entitles the recipient one common unit of the Partnership for each phantom unit.

The following table presents the phantom unit activity under the LTIP for the six months ended June 30, 2015:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	17,776	$19.51
Granted	—	$—
Vested	(8,888)	$19.51
Unvested at June 30, 2015	8,888	$19.51

The aggregate fair value of restricted stock units that vested during the six months ended June 30, 2015 was $0.2 million. As of June 30, 2015, the unrecognized compensation cost related to unvested phantom units was $0.2 million. Such cost is expected to be recognized over a weighted-average period of 1.0 years.

7. 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 June 30, 2015, the Partnership had a total of 79,717,776 common units issued and outstanding, of which 70,450,000 common units were owned by Diamondback, representing approximately 88% of the total Partnership common units outstanding.

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

	Common Units
Diamondback Energy, Inc. ownership of common units	70,450,000
Common units issued in June 23, 2014 IPO	5,750,000
Common units issued in September 19, 2014 public offering	3,500,000
Common units vested and issued under the 2014 LTIP	17,776
Balance June 30, 2015	79,717,776

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 ended September 30, 2014. On February 5, 2015, the board of directors of the General Partner approved a cash distribution attributable to the fourth quarter of 2014 of $0.25 per common unit, which was paid on February 27, 2015. This distribution included a total of $17.6 million distributed to Diamondback. On May 1, 2015, the board of directors of the General Partner approved a cash distribution attributable to the first quarter of 2015 of $0.19 per common unit, which was paid on May 22, 2015. This distribution included a total of $13.4 million distributed to Diamondback. Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of the General Partner following the end of such quarter.

Available cash for each quarter will generally equal Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors of the General Partner deems necessary or appropriate, if any.

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8. EARNINGS PER UNIT

The net income per common unit on the consolidated statements of operations is based on the net income of the Partnership for the three months and six months ended June 30, 2015 and for the period after the closing of the IPO on June 23, 2014 through June 30, 2014, since this is the amount of net income that is attributable to the Partnership's common units.

The Partnership's net income is allocated wholly to the common units as the General Partner does not have an economic interest. Payments made to the Partnership's unitholders are determined in relation to the cash distribution policy described in Note 7—Partners' Capital and Partnership Distributions.

Basic net income per common unit is calculated by dividing net income 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.

	Three Months Ended June 30, 2015	June 23, 2014 to June 30, 2014
	(In thousands, except per unit amounts)	
Net income attributable to period	$8,045	$941
Net income per common unit, basic	$0.10	$0.01
Net income per common unit, diluted	$0.10	$0.01
Weighted-average common units outstanding, basic	79,710	76,200
Weighted-average common units outstanding, diluted	79,710	76,200

	Six Months Ended June 30, 2015	June 23, 2014 to June 30, 2014
	(In thousands, except per unit amounts)	
Net income attributable to period	$13,127	$941
Net income per common unit, basic	$0.16	$0.01
Net income per common unit, diluted	$0.16	$0.01
Weighted-average common units outstanding, basic	79,710	76,200
Weighted-average common units outstanding, diluted	79,710	76,200

9. 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.

10. SUBSEQUENT EVENTS

On July 31, 2015, the board of directors of the General Partner approved a cash distribution for the second quarter of 2015 of $0.22 per common unit, payable on August 21, 2015, to unitholders of record at the close of business on August 14, 2015.

On July 9, 2015, the Partnership completed the acquisition of 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 partially

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funded with borrowings under the Partnership's revolving credit facility discussed in Note 8 above. As of July 9, 2015, the Partnership had $24.0 million outstanding under its revolving credit facility.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this Quarterly Report on Form 10-Q as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2014 . 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 "Part II. 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 June 30, 2015, the general partner held a 100% non-economic general partner interest in us, and Diamondback had an approximate 88% limited partner interest in us. Diamondback also owns and controls the general partner.

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.

Recent Developments

On July 9, 2015, we completed the acquisition of 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 partially funded with borrowings under our revolving credit facility. As of July 9, 2015, we had $24.0 million outstanding under its revolving credit facility.

Sources of Our Revenue

Our revenues are derived from royalty payments we receive from our operators based on the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from natural gas during processing. For the three months ended June 30, 2015, our revenues were derived 93% from oil sales, 4% from natural gas liquid sales and 3% from natural gas sales and for the three months ended June 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquid sales and 3% from natural gas sales. For the six months ended June 30, 2015, our revenues were derived 94% from oil sales, 3% from natural gas liquid sales and 3% from natural gas sales and for the six months ended June 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquid sales and 3% from natural gas sales. 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. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2014, West Texas Intermediate posted prices ranged from $53.45 to $107.95 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.74 to $8.15 per MMBtu. On June 30, 2015, the West Texas Intermediate posted price for crude oil was $59.47 per Bbl and the Henry Hub spot market price of natural gas was $2.80 per MMBtu. Since June 2014, oil prices have declined from over $105.00 per Bbl to a range of prices between $45 per Bbl and $60 per Bbl for the six months ended June 30, 2015 due in large part to increasing supplies and weakening demand growth. 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 determined 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 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.

In connection with the closing of the IPO, we and our general partner entered into an advisory services agreement with Wexford, pursuant to which Wexford provides general financial and strategic advisory services to us and our general partner in exchange for a $0.5 million annual fee and certain expense reimbursement.

Our predecessor incurred costs for overhead, including the cost of management, operating and administrative services provided under the shared services agreement with Diamondback E&P LLC, a wholly owned subsidiary of Diamondback, audit and other fees for professional services and legal compliance. In connection with the closing of the IPO, the shared services agreement with Diamondback E&P LLC was terminated.

Depreciation, Depletion and Amortization

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

Income Tax Expense

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. Any amounts related to operations for 2013 or for the period in 2014 prior to the closing of the IPO on June 23, 2014 will be included in Diamondback’s unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for the three months and six months ended June 30 in each of 2015 or 2014.

Results of Operations

Results Presented and Factors Affecting the Comparability of Our Results to the Historical Financial Results of Our Predecessor

Viper Energy Partners LP was formed on February 27, 2014 and did not own any assets prior to the contribution of the predecessor to us on June 17, 2014. The assets of our predecessor consisted of mineral interests in oil and natural gas properties in the Permian Basin, which were acquired on September 19, 2013. The contribution of our predecessor to us on June 17, 2014 was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. Therefore, the financial and operating data below represent our predecessor’s operations for periods prior to June 17, 2014 and, for periods on and after June 17, 2014, the financial and operating data represent the combination of the predecessor and our operations. Our results of operations and our future results of operations may not be comparable to the historical results of operations of our predecessor for the periods presented, primarily for the reasons described below:

Long-Term Debt

- In connection with the closing of the IPO, the subordinated note issued by our predecessor to Diamondback effective September 19, 2013 was converted to equity; therefore, we no longer have the note payable and related interest expense.
- On July 8, 2014, we entered into a secured revolving credit agreement with Wells Fargo Bank, National Association, or Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement, as amended, provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be redetermined semi-annually with effective dates of April 1st and October 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any

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12-month period. As of June 30, 2015, the borrowing base was set at $175.0 million and we had no outstanding borrowings.

General and Administrative

- We anticipate incurring incremental general and administrative expenses of approximately $2.5 million annually as a result of being a publicly traded partnership, consisting of expenses associated with SEC reporting requirements, including annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, Sarbanes-Oxley Act compliance, NASDAQ Global Select Market listing, independent auditor fees, legal fees, investor relations activities, registrar and transfer agent fees, director and officer insurance and director compensation.
- The partnership agreement requires us to reimburse the general partner for all direct and indirect expenses incurred or paid on our behalf and all other expenses allocable to us or otherwise incurred by our general partner in connection with operating our business. The partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine the expenses that are allocable to us. For the six months ended June 30, 2015, no expenses were allocated to us by the general partner for reimbursement.
- On June 17, 2014, under the Long Term Incentive Plan, or LTIP, adopted in connection with the IPO, we granted awards of an aggregate of 2,500,000 unit options under the LTIP to executive officers of the general partner. For the three months and six months ended June 30, 2015, we incurred $0.9 million and $1.9 million, respectively, of unit–based compensation.
- In connection with the closing of the IPO, we and our general partner entered into an advisory services agreement with Wexford pursuant to which Wexford provides general financial and strategic advisory services to us and our general partner in exchange for a $0.5 million annual fee and certain expense reimbursement. For the three months and six months ended June 30, 2015, we incurred costs of $0.1 million and $0.3 million, respectively, under the advisory services agreement.
- 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 for which our results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax 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 less or no tax. In such a situation, we would reimburse Diamondback for the tax we would have owed had the tax attributes not been available or used for our benefit, even though Diamondback had no cash tax expense for that period.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(unaudited, in thousands, except production data)			
Operating Results:				
Royalty income	$19,619	$17,249	$36,164	$33,102
Costs and expenses:				
Production and ad valorem taxes	1,417	1,392	2,745	2,313
Depletion	8,949	6,064	17,850	11,631
General and administrative expenses	1,168	219	2,595	285
General and administrative expenses—related party	139	78	264	156
Total costs and expenses	11,673	7,753	23,454	14,385
Income from operations	7,946	9,496	12,710	18,717
Other income (expense)				
Interest expense	(207)	—	(375)	—
Interest expense—related party, net of capitalized interest	—	(5,387)	—	(10,755)
Other income	306	—	792	—
Total other income (expense), net	99	(5,387)	417	(10,755)
Net income	$8,045	$4,109	$13,127	$7,962
Production Data:				
Oil (Bbls)	342,869	164,957	694,236	319,704
Natural gas (Mcf)	239,470	134,301	459,122	239,032
Natural gas liquids (Bbls)	56,956	33,632	104,956	56,803
Combined volumes (BOE)	439,737	220,972	875,712	416,346
Daily combined volumes (BOE/d)	4,832	2,428	4,838	2,300
% Oil	78%	75%	79%	77%

Comparison of the Three Months Ended June 30, 2015 and 2014

Royalty Income

Our royalty income for the three months ended June 30, 2015 and 2014 was $19.6 million and $17.2 million, respectively.

Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes. Our operators received an average of $53.40 per Bbl of oil, $13.99 per Bbl of natural gas liquids and $2.15 per Mcf of natural gas for the volumes sold for the three months ended June 30, 2015. Our operators received an average of $95.23 per Bbl of oil, $28.22 per Bbl of natural gas liquids and $4.40 per Mcf of natural gas for the volumes sold for the three months ended June 30, 2014.

General and Administrative Expenses

The general and administrative expenses primarily reflect unit-based compensation, the amounts reimbursed to our general partner under our partnership agreement and amounts incurred under our advisory services agreement. For the three months ended June 30, 2015 and 2014, we incurred general and administrative expenses of $1.3 million and $0.3 million, respectively.

Net Interest Expense

The net interest expense for the three months ended June 30, 2015 reflects the interest incurred under our credit agreement. The net interest expense for the three months ended June 30, 2014 primarily relates to interest incurred under the

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subordinate note of the predecessor. Net interest expense for the three months ended June 30, 2015 and 2014 was $0.2 million and $5.4 million, respectively.

Comparison of the Six Months Ended June 30, 2015 and 2014

Royalty Income

Our royalty income for the six months ended June 30, 2015 and 2014 was $36.2 million and $33.1 million, respectively.

Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes. Our operators received an average of $48.75 per Bbl of oil, $11.81 per Bbl of natural gas liquids and $2.36 per Mcf of natural gas for the volumes sold for the six months ended June 30, 2015. Our operators received an average of $94.52 per Bbl of oil, $31.51 per Bbl of natural gas liquids and $4.58 per Mcf of natural gas for the volumes sold for the six months ended June 30, 2014.

General and Administrative Expenses

The general and administrative expenses primarily reflect unit-based compensation, the amounts reimbursed to our general partner under our partnership agreement and amounts incurred under our advisory services agreement. For the six months ended June 30, 2015 and 2014, we incurred general and administrative expenses of $2.9 million and $0.4 million, respectively.

Net Interest Expense

The net interest expense for the six months ended June 30, 2015 reflects the interest incurred under our credit agreement. The net interest expense for the six months ended June 30, 2014 primarily relates to interest incurred under the subordinate note of the Predecessor. Net interest expense for the six months ended June 30, 2015 and 2014 was $0.4 million and $10.8 million, respectively.

Adjusted EBITDA

Adjusted EBITDA is used as a supplemental non-GAAP financial measure 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 period to period without regard to our financing methods or capital structure. In addition, management uses Adjusted EBITDA to evaluate cash flow available to pay distributions to our unitholders.

We define Adjusted EBITDA as net income (loss) plus interest expense, net of capitalized interest, non-cash unit-based compensation and depletion expense. Adjusted EBITDA is not a measure of the 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 historic costs of depreciable assets, none of which are components of Adjusted EBITDA.

Adjusted EBITDA should not be considered an alternative to net income, royalty income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. 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 net income, our most directly comparable GAAP financial measure for the periods indicated.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Net Income	$8,045	$4,109	$13,127	$7,962
Interest expense, net of capitalized interest	207	5,387	375	10,755
Non-cash unit-based compensation expense	939	128	1,878	128
Depletion	8,949	6,064	17,850	11,631
Adjusted EBITDA	$18,140	$15,688	$33,230	$30,476

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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 will be for paying distributions to our unitholders and for replacement and growth capital expenditures, including the acquisition, development and exploration of oil and natural gas properties. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including weather, commodity prices, and general economic, financial, competitive, legislative, regulatory and other factors.

Our partnership agreement does not require us to distribute any of the cash we generate from operations. We believe, however, that it will be in the best interests of our unitholders if we distribute a substantial portion of the cash we generate from operations. The board of directors of our general partner has adopted a policy to distribute an amount equal to the available cash we generate each quarter to our unitholders. On February 5, 2015, the board of directors of the General Partner approved a cash distribution attributable to the fourth quarter of 2014 of $0.25 per common unit, which was paid on February 27, 2015. This distribution included a total of $17.6 million distributed to Diamondback. On May 1, 2015, the board of directors of the general partner approved a cash distribution attributable to the first quarter of 2015 of $0.19 per common unit, which was paid on May 22, 2015. This distribution included a total of $13.4 million distributed to Diamondback. Cash distributions will be made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter will be determined by the board of directors of our general partner following the end of such quarter. Available cash for each quarter will generally equal Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors of our general partner deems necessary or appropriate, if any.
Our Credit Agreement
On July 8, 2014, we entered into a $500.0 million secured revolving credit agreement with Wells Fargo as the administrative agent, sole book runner and lead arranger. The credit agreement, which was amended August 15, 2014 to add additional lenders to the lending group, matures on July 8, 2019. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. As of June 30, 2015, the borrowing base remained at $175.0 million and we had no outstanding borrowings. On July 9, 2015, we borrowed $24.0 million to fund a portion of the purchase price for certain overriding royalty interests. See"—Recent Developments."
The outstanding borrowings under the credit agreement bear interest at a rate elected by us that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We are obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of July 8, 2019. The loan is secured by substantially all of our and our subsidiaries' assets.
The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, purchases of margin stock, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio

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

EBITDAX is annualized for the four fiscal quarters ending on the last day of the fiscal quarter for which financial statements are available, beginning with the quarter ended September 30, 2014.

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

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

Cash Flows

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

	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
	(in thousands)	
Cash Flow Data:		
Cash flows provided by operating activities	$30,173	$14,064
Cash flows provided by (used in) investing activities	77	(5,275)
Cash flows used in financing activities	(35,372)	(2,522)
Net increase (decrease) in cash	$(5,122)	$6,267

Operating Activities

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

Investing Activities

We used cash for investing activities of $5.3 million during the six months ended June 30, 2014 related to capitalized interest on the subordinated note used to purchase mineral interests.

Financing Activities

Net cash used in financing activities of $35.4 million during the six months ended June 30, 2015 primarily relates to our distribution to our unitholders in February and May 2015. We used cash for financing activities of $2.5 million during the six months ended June 30, 2014 primarily for interest payments on the subordinated note. In connection with the closing of the IPO, we agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.3 million and the net proceeds from the IPO. As of June 30, 2014, we had distributed $137.5 million to Diamondback.

Contractual Obligations

There were no material changes in our contractual obligations and other commitments, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014.

Critical Accounting Policies

There have been no changes to our critical accounting policies from those disclosed in the our Annual Report on Form 10-K for the year ended December 31, 2014.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements.

ITEM 3. 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

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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 six months ended June 30, 2015, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (US) Company (71%) and RSP Permian LLC (23%). For the six months ended June 30, 2014, two purchasers accounted for more than 10% of royalty interest revenue: Shell Trading (US) Company (70%) and Permian Transport and Trading (12%). 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 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We entered into this credit agreement on July 8, 2014, and as of June 30, 2015, we had no outstanding borrowings. On July 9, 2015, we borrowed $24.0 million under our credit agreement. An increase or decrease of 1% in the interest rate on this outstanding borrowing would have a corresponding decrease or increase in our interest expense of approximately $240,000 based on the $24.0 million outstanding in the aggregate under our credit agreement on July 9, 2015.

ITEM 4. 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 June 30, 2015, 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 June 30, 2015, 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 quarter ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

ITEM 1A. RISK FACTORS

Our business faces many risks. Any of the risks discussed in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

In addition to the information set forth in this Form 10–Q, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10–K for the year ended December 31, 2014 and in subsequent filings we make with the SEC. There have been no material changes in our risk factors from those described in our Annual Report on Form 10–K for the year ended December 31, 2014.

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ITEM 6. EXHIBITS

Exhibit Number	Description
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*	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.
10.2*	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.
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.
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 certifications attached as Exhibit 32.1 accompany this Quarterly Report on Form 10-Q 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 Quarterly Report to be signed on its behalf by the undersigned thereunto duly authorized.

	VIPER ENERGY PARTNERS LP
	By: VIPER ENERGY PARTNERS GP LLC its General Partner
Date: August 10, 2015	By: /s/ Travis D. Stice Travis D. Stice Chief Executive Officer
Date: August 10, 2015	By: /s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer