

Viper Energy Partners LP
Form 10-Q
November 08, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

✓ QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2016

OR

° 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)
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500 West Texas, Suite 1200 Midland, Texas (Address of Principal Executive Offices)	79701 (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 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 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

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company” in Rule 12b-2 of the Exchange Act. (Check One):

Large Accelerated Filer Accelerated Filer

Non-Accelerated Filer Smaller Reporting Company

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

As of November 3, 2016, 87,800,356 common limited partner units of the registrant were outstanding.

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FOR THE QUARTER ENDED SEPTEMBER 30, 2016
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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and gas terms that are used in this Quarterly Report on Form 10-Q (this “report”):

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.
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, or Btu	The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
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.
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.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
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.
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 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.
Reserves	The 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 are not 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.

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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.
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.

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GLOSSARY OF CERTAIN OTHER TERMS

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

Diamondback	Diamondback Energy, Inc., a Delaware corporation.
Exchange Act	The Securities Exchange Act of 1934, as amended.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company, and the General Partner of the Partnership.
IPO	The Partnership's initial public offering.
LTIP	Viper Energy Partners LP Long Term Incentive Plan.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The first amended and restated agreement of limited partnership, dated 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.
SEC	United States Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
Wells Fargo	Wells Fargo Bank, National Association.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this 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 report, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “predict,” “potential,” “project,” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this report, including those detailed under Part II. Item 1A. Risk Factors in this 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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Consolidated Balance Sheets
(Unaudited)

	September 30, 2016	December 31, 2015
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	\$7,758	\$539
Restricted cash	500	500
Royalty income receivable	9,918	9,369
Other current assets	93	476
Total current assets	18,269	10,884
Property and equipment:		
Oil and natural gas interests, full cost method of accounting (\$199,401 and \$85,329 excluded from depletion at September 30, 2016 and December 31, 2015, respectively)	692,816	554,992
Accumulated depletion and impairment	(140,613)	(71,659)
Oil and natural gas interests, net	552,203	483,333
Other assets	34,897	35,514
Total assets	\$605,369	\$529,731
Liabilities and Unitholders' Equity		
Current liabilities:		
Accounts payable	\$37	\$1
Accounts payable—related party	—	4
Other accrued liabilities	1,753	82
Total current liabilities	1,790	87
Long-term debt	54,500	34,500
Total liabilities	56,290	34,587
Commitments and contingencies (Note 10)		
Unitholders' equity:		
Common units (87,800,356 units issued and outstanding as of September 30, 2016 and 79,726,006 units issued and outstanding as of December 31, 2015)	549,079	495,144
Total unitholders' equity	549,079	495,144
Total liabilities and unitholders' equity	\$605,369	\$529,731

See accompanying notes to consolidated financial statements.

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Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
	2016	2015	2016	2015
	(In thousands, except per unit amounts)			
Operating income:				
Royalty income	\$19,992	\$18,777	\$50,914	\$54,941
Lease bonus	5	—	309	—
Total operating income	19,997	18,777	51,223	54,941
Costs and expenses:				
Production and ad valorem taxes	1,429	1,686	4,134	4,431
Gathering and transportation	70	167	247	167
Depletion	6,751	8,737	21,485	26,587
Impairment	—	—	47,469	—
General and administrative expenses	1,153	1,642	4,109	4,501
Total costs and expenses	9,403	12,232	77,444	35,686
Income (loss) from operations	10,594	6,545	(26,221)	19,255
Other income (expense):				
Interest expense	(658)	(358)	(1,544)	(733)
Other income	266	168	612	960
Total other income (expense), net	(392)	(190)	(932)	227
Net income (loss)	\$10,202	\$6,355	\$(27,153)	\$19,482
Net income attributable to common limited partners per unit:				
Basic and Diluted	\$0.12	\$0.08	\$(0.33)	\$0.24
Weighted average number of limited partner units outstanding:				
Basic	84,996	79,721	81,496	79,713
Diluted	85,003	79,730	81,496	79,728

See accompanying notes to consolidated financial statements.

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Statements of Consolidated Unitholders' Equity
(Unaudited)

	Limited Partners Common		
	Units	Amount	Total
	(In thousands)		
Balance at December 31, 2014	79,709	\$535,351	\$535,351
Unit-based compensation	17	2,956	2,956
Distributions to public	—	(6,113)	(6,113)
Distributions to Diamondback	—	(46,496)	(46,496)
Net income	—	19,482	19,482
Balance at September 30, 2015	79,726	\$505,180	\$505,180
Balance at December 31, 2015	79,726	\$495,144	\$495,144
Net proceeds from the issuance of common units - Public	6,050	94,380	94,380
Net proceeds from the issuance of common units - Diamondback	2,000	31,200	31,200
Offering Costs	—	(816)	(816)
Unit-based compensation	24	2,974	2,974
Distributions to public	—	(6,397)	(6,397)
Distributions to Diamondback	—	(40,253)	(40,253)
Net loss	—	(27,153)	(27,153)
Balance at September 30, 2016	87,800	\$549,079	\$549,079

See accompanying notes to consolidated financial statements.

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Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30, 2016 2015 (In thousands)	
Cash flows from operating activities:		
Net income (loss)	\$(27,153)	\$19,482
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion	21,485	26,587
Impairment	47,469	—
Amortization of debt issuance costs	280	224
Non-cash unit-based compensation	2,974	2,956
Changes in operating assets and liabilities:		
Royalty income receivable	(549)	(2,357)
Accounts payable—related party	(4)	—
Accounts payable and other accrued liabilities	1,707	53
Prepaid expenses and other current assets	345	(972)
Net cash provided by operating activities	46,554	45,973
Cash flows from investing activities:		
Additions to oil and natural gas interests	—	71
Acquisition of royalty interests	(137,786)	(32,291)
Net cash used in investing activities	(137,786)	(32,220)
Cash flows from financing activities:		
Proceeds from borrowings under credit facility	98,000	29,000
Repayment on credit facility	(78,000)	—
Debt issuance costs	(35)	(303)
Proceeds from public offerings	125,580	—
Public offering costs	(444)	—
Distributions to partners	(46,650)	(52,609)
Net cash provided by (used in) financing activities	98,451	(23,912)
Net increase (decrease) in cash	7,219	(10,159)
Cash and cash equivalents at beginning of period	539	15,110
Cash and cash equivalents at end of period	\$7,758	\$4,951
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	\$1,251	\$495
See accompanying notes to consolidated financial statements.		

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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. (“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”).

As of September 30, 2016, Viper Energy Partners GP LLC (the “General Partner”), held a 100% non-economic general partner interest in the Partnership and Diamondback had an approximate 83% 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 GAAP. All material intercompany balances and transactions are eliminated in consolidation.

These financial statements have been prepared by the Partnership without audit, pursuant to the rules and regulations of the SEC. They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been omitted pursuant to such rules and regulations, although the Partnership believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10-Q should be read in conjunction with the Partnership’s most recent Annual Report on Form 10-K for the fiscal year ended December 31, 2015, which contains a summary of the Partnership’s significant accounting policies and other disclosures.

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 interests and unit-based compensation.

New Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, “Interest–Imputation of Interest”. This update requires that debt issuance costs related to a recognized debt liability (except costs associated with revolving debt arrangements) 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. This update is effective for financial statements issued for fiscal years beginning after December 15, 2015. The Partnership retrospectively adopted this new standard effective January 1, 2016. Adoption of this update did not have a material impact on the Partnership’s consolidated financial statements.

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Notes to Financial Statements - (Continued)

(unaudited)

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. This update will be effective for public entities for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. Entities should apply the amendments by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The Partnership will be required to mark its cost method investment to fair value with the adoption of this update.

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. The Partnership is currently evaluating the impact that the adoption of this update will have on the Partnership's financial position, results of operations and liquidity.

In March 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-08, "Revenue from Contracts with Customers - Principal versus Agent Considerations (Reporting Revenue Gross versus Net)". Under this update, an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This update will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. This update allows for either full retrospective adoption, meaning this update is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning this update is applied only to the most current period presented. The Partnership is currently evaluating the impact, if any, that the adoption of this update will have on the Partnership's financial position, results of operations and liquidity.

In March 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-09, "Compensation - Stock Compensation". This update applies to all entities that issue equity-based payment awards to their employees. Under this update, there were several areas that were simplified including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years with early adoption permitted. The Partnership is currently evaluating the impact that the adoption of this update will have on the Partnership's financial position, results of operations and liquidity.

In April 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-10, "Revenue from Contracts with Customers - Identifying Performance Obligations and Licensing". This update clarifies two principles of Accounting Standards Codification Topic 606: identifying performance obligations and the licensing implementation guidance. This standard has the same effective date as Accounting Standards Update 2016-08, the

revenue recognition standard discussed above. The adoption of this standard is not expected to have a material impact on the Partnership's financial position, results of operations and liquidity.

In May 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-12, "Revenue from Contracts with Customers - Narrow-Scope Improvements and Practical Expedients". This update applies only to the following areas from Accounting Standards Codification Topic 606: assessing the collectability criterion and accounting for contracts that do not meet the criteria for step 1, presentation of sales taxes and other similar taxes collected from customers, noncash consideration, contract modification at transition, completed contracts at transition and technical correction. This standard has the same effective date as Accounting Standards Update 2016-08, the revenue recognition standard discussed above. The adoption of this standard is not expected to have a material impact on the Partnership's financial position, results of operations and liquidity.

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Viper Energy Partners LP

Notes to Financial Statements - (Continued)

(unaudited)

3. ACQUISITIONS

On July 22, 2016, the Partnership acquired from an unrelated third party mineral interests underlying 7,487 gross (601 net royalty) acres in the Midland Basin, with approximately 300 BOE/d of estimated August 2016 net production, for \$79.0 million.

In July 2016, the Partnership also acquired from unrelated third parties mineral interests underlying an additional 9,281 gross (152 net royalty) acres in the Permian Basin for an aggregate of \$11.7 million.

The purchase price for each of the above described acquisitions was primarily funded with borrowings under the Partnership's revolving credit facility.

On August 16, 2016, the Partnership acquired from an unrelated third party mineral interests in 650 gross (142 net royalty) acres in the Delaware Basin, with approximately 200 BOE/d of estimated August 2016 net production, for approximately \$31.4 million, subject to post-closing adjustments. The Partnership used a portion of the net proceeds of its August 2016 public offering of common units to fund this acquisition.

4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	September	December
	30,	31,
	2016	2015

(in thousands)

Oil and natural gas interests:

Subject to depletion	\$493,415	\$469,663
Not subject to depletion-acquisition costs		
Incurred in 2016	115,261	—
Incurred in 2015	38,750	39,693
Incurred in 2014	45,390	45,636
Total not subject to depletion	199,401	85,329
Gross oil and natural gas interests	692,816	554,992
Accumulated depletion and impairment	(140,613)	(71,659)
Oil and natural gas interests, net	\$552,203	\$483,333

Costs associated with unevaluated interests 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 a non-cash impairment for the nine months ended September 30, 2016 of \$47.5 million, which is included in accumulated depletion and impairment. There were no impairments recorded for the nine months ended September 30, 2015. The impairment charge 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.

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Viper Energy Partners LP

Notes to Financial Statements - (Continued)

(unaudited)

5. DEBT

Credit Agreement-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. 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 is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2016, the borrowing base was set at \$175.0 million. On August 5, 2016, the Partnership repaid \$78.0 million of its outstanding borrowings with a portion of the proceeds from the Partnership's August 2016 public offering of common units and, as of September 30, 2016, the Partnership had \$54.5 million outstanding under its credit agreement.

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 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of 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 repaid (a) to the extent that 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

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 Partnership's 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.

6. 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, 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

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Viper Energy Partners LP

Notes to Financial Statements - (Continued)

(unaudited)

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 three and nine months ended September 30, 2016 and 2015, no expenses were allocated to the Partnership by the General Partner.

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 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 and nine months ended September 30, 2016, the Partnership did not pay any costs under the Advisory Services Agreement. For the three and nine months ended September 30, 2015, the Partnership paid costs of \$0.1 million and \$0.4 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 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 three months ended September 30, 2016, Diamondback paid the Partnership \$5,000 in lease bonus payments to extend the term of two leases, reflecting an average bonus of \$200 per acre. During the nine months ended September 30, 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 9,144,000 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 and nine months ended September 30, 2016, the Partnership incurred \$1.0 million and \$3.0 million, respectively, of unit-based compensation.

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Viper Energy Partners LP

Notes to Financial Statements - (Continued)

(unaudited)

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 nine months ended September 30, 2016:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2015	25,348	\$ 16.89
Granted	21,696	\$ 16.57
Vested	(24,350)	\$ 17.27
Forfeited	(1,646)	\$ 15.48
Unvested at September 30, 2016	21,048	\$ 16.23

The aggregate fair value of phantom units that vested during the nine months ended September 30, 2016 was \$0.4 million. As of September 30, 2016, the unrecognized compensation cost related to unvested phantom units was \$0.3 million. Such cost is expected to be recognized over a weighted-average period of 1.7 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 September 30, 2016, the Partnership had a total of 87,800,356 common units issued and outstanding, of which 72,450,000 common units were owned by Diamondback, representing approximately 83% of the total Partnership common units outstanding.

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

	Common Units
Balance at December 31, 2015	79,726,006
Common units issued in August 2016 public offering	8,050,000
Common units vested and issued under the LTIP	24,350
Balance at September 30, 2016	87,800,356

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.

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On February 12, 2016, the board of directors of the General Partner approved a cash distribution for the fourth quarter of 2015 of \$0.228 per common unit, payable on February 26, 2016, to unitholders of record at the close of business on February 19, 2016.

On May 2, 2016, the board of directors of the General Partner approved a cash distribution for the first quarter of 2016 of \$0.149 per common unit, payable on May 23, 2016, to unitholders of record at the close of business on May 16, 2016.

On July 21, 2016, the board of directors of the General Partner approved a cash distribution for the second quarter of 2016 of \$0.189 per common unit, payable on August 22, 2016, to unitholders of record at the close of business on August 15, 2016.

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

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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.

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 three and nine months ended September 30, 2016 and 2015, since this is the amount of net income (loss) 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.

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
	2016	2015	2016	2015
	(In thousands, except per unit amounts)			
Net income (loss) attributable to the period	\$10,203	\$6,355	\$(27,153)	\$19,482
Net income per common unit, basic	\$0.12	\$0.08	\$(0.33)	\$0.24
Net income per common unit, diluted	\$0.12	\$0.08	\$(0.33)	\$0.24
Weighted-average common units outstanding, basic	84,996	79,721	81,496	79,713
Weighted-average common units outstanding, diluted	85,003	79,730	81,496	79,728

For the three and nine months ended September 30, 2016, there were 1,514,069 common units and 1,583,376 common units, respectively, that were not included in the computation of diluted earnings per common unit because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per common 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.

Litigation

The Partnership filed an action in October 2014 to recover \$0.5 million held in escrow in connection with a purchase and sale agreement. The escrow agent interpleaded the funds, and the other parties to the agreement have filed a

counterclaim to recover the escrow. Both sides also seek recovery of their attorneys' fees. The case is expected to be scheduled for trial in the first quarter of 2017. It is not possible to predict the outcome with reasonable certainty, but the Partnership does not believe that an adverse outcome would have a material adverse effect on the Partnership's financial statements and has not included a loss contingency reserve for this matter.

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11. SUBSEQUENT EVENTS

Cash Distribution

On October 25, 2016, the board of directors of the General Partner approved a cash distribution for the third quarter of 2016 of \$0.207 per common unit, payable on November 18, 2016, to unitholders of record at the close of business on November 11, 2016.

The Partnership's Credit Facility

In connection with the Partnership's fall 2016 redetermination, the agent lender under the credit agreement has recommended that the Partnership's borrowing base be increased to \$275.0 million.

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 report as well as our audited financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2015. 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 September 30, 2016, our general partner held a 100% non-economic general partner interest in us, and Diamondback had an approximate 83% limited partner interest in us. Diamondback also owns and controls our general partner.

In August 2016, we completed an underwritten public offering of 8,050,000 common units, which included 1,050,000 common units issued pursuant to an option to purchase additional common units granted to the underwriter. In this offering, Diamondback purchased 2,000,000 common units from the underwriter at \$15.60 per unit, which is the price per common unit paid by the underwriter to us. Following the August 2016 public offering, Diamondback had an approximate 83% limited partner interest in us. We received net proceeds from this offering of approximately \$125.1 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we used to fund the purchase price for the acquisition described below and repaid outstanding borrowings under our revolving credit facility.

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 interests principally located in the Permian Basin of West Texas.

Sources of Our Income

Our income is 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

payments may vary significantly from period to period as a result of commodity prices, production mix and volumes of production sold by our operators.

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

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
Royalty income				
Oil sales	90	%92	% 91	%93
Natural gas sales	4	%4	% 4	%3
Natural gas liquid sales	6	%4	% 5	%4
	100	%100	%100	%100

As a result, our income is more sensitive to fluctuations in oil prices than is it to fluctuations in natural gas liquids or natural gas prices. Our income 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 2015, West Texas Intermediate posted prices ranged from \$34.55 to \$61.36 per Bbl and the Henry Hub spot market price of natural gas ranged from \$1.63 to \$3.32 per MMBtu. On September 30, 2016, the West Texas Intermediate posted price for crude oil was \$47.72 per Bbl and the Henry Hub spot market price of natural gas was \$2.84 per MMBtu. Lower prices may not only decrease our income, 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.

As a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves, we recorded a non-cash impairment to the book value of our oil and natural gas interests for the nine months ended September 30, 2016 of \$47.5 million.

Production and Operational Update

Our average daily production during the third quarter of 2016 was 6,255 BOE/d (75% oil), and our operators received an average of \$41.97 per Bbl of oil, \$12.56 per Bbl of natural gas liquids and \$2.39 per Mcf of natural gas, for an average realized price of \$34.74 per BOE.

During the third quarter of 2016, the operators of our Spanish Trail mineral interests brought online 20 gross horizontal wells, consisting of 14 Lower Spraberry, three Wolfcamp A, two Wolfcamp B, and one Middle Spraberry well. As of September 30, 2016, there were approximately 20 horizontal wells in various stages of drilling or completion on this acreage. Additionally there is active development activity on our mineral acreage outside of Spanish Trail in Loving, Reeves, Midland, Howard and Glasscock counties, including acreage that was part of our recent acquisitions. As of September 30, 2016, we have 559 vertical wells and 163 horizontal wells producing on our acreage. There are approximately 95 undrilled permitted wells and five active rigs currently on our mineral acreage.

We declared a cash dividend for the third quarter of 2016 of \$0.207 per common unit, payable on November 18, 2016, to unitholders of record at the close of business on November 11, 2016.

Recent Acquisitions

On July 22, 2016, we acquired from an unrelated third party mineral interests underlying 7,487 gross (601 net royalty) acres in the Midland Basin, with approximately 300 BOE/d of estimated August 2016 net production, for \$79.0 million. Estimated net proved reserves, based on internal estimates as of July 1, 2016, were approximately 1.0 MMBOE. Our internal estimate of net proved reserves is based on our analysis of production data provided by the seller, as well as geologic and other data, and has not been reviewed by our independent petroleum engineers. We believe this acreage is prospective in the Wolfcamp A, Wolfcamp B, Lower Spraberry and Middle Spraberry horizons.

In July 2016, we also acquired from unrelated third parties mineral interests underlying an additional 9,281 gross (152 net royalty) acres in the Permian Basin for an aggregate of \$11.7 million.

The purchase price for each of the above described recent acquisitions was primarily funded with borrowings under our revolving credit facility.

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On August 16, 2016, we acquired from an unrelated third party mineral interests in 650 gross (142 net royalty) acres in the Delaware Basin, with approximately 200 BOE/d of estimated August 2016 net production, for approximately \$31.4 million, subject to post-closing adjustments. Estimated net proved reserves, based on internal estimates as of August 1, 2016, were approximately 0.6 MMBOE. Our internal estimate of net proved reserves is based on our analysis of production data provided by the seller, as well as geologic and other data, and has not been reviewed by our independent petroleum engineers. We believe this acreage is prospective in the Wolfcamp, Bone Springs, Avalon Shale and Brushy Canyon horizons. We used a portion of the net proceeds of our August 2016 public offering of common units to fund the purchase price of this acquisition.

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 interests.

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.

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.

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 interests 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 the period in 2014 prior to the closing of the IPO on June 23, 2014 was included in Diamondback's unitary filing for this tax. Diamondback does not expect any Texas margin tax to be due for the nine months ended September 30, 2016 or 2015.

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Results of Operations

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2016	2015	2016	2015
	(unaudited, in thousands, except production data)			
Operating Results:				
Operating income:				
Royalty income	\$ 19,992	\$ 18,777	\$ 50,914	\$ 54,941
Lease bonus	5	—	309	—
Total operating income	19,997	18,777	51,223	54,941
Costs and expenses:				
Production and ad valorem taxes	1,429	1,686	4,134	4,431
Gathering and transportation	70	167	247	167
Depletion	6,751	8,737	21,485	26,587
Impairment	—	—	47,469	—
General and administrative expenses	1,153	1,642	4,109	4,501
Total costs and expenses	9,403	12,232	77,444	35,686
Income (loss) from operations	10,594	6,545	(26,221)	19,255
Other income (expense):				
Interest expense	(658)	(358)	(1,544)	(733)
Other income	266	168	612	960
Total other income (expense), net	(392)	(190)	(932)	227
Net income (loss)	\$ 10,202	\$ 6,355	\$ (27,153)	\$ 19,482
Production Data:				
Oil (Bbls)	430,732	391,757	1,236,003	1,085,993
Natural gas (Mcf)	315,030	316,323	1,008,745	775,445
Natural gas liquids (Bbls)	92,221	81,339	221,582	186,295
Combined volumes (BOE)	575,458	525,817	1,625,709	1,401,529
Daily combined volumes (BOE/d)	6,255	5,715	5,933	5,134
% Oil	75	% 75	% 76	% 77

Comparison of the Three Months Ended September 30, 2016 and 2015

Royalty Income

Our royalty income for the three months ended September 30, 2016 and 2015 was \$20.0 million and \$18.8 million, respectively. Our income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

The following table summarizes the average amounts received by our operators for the three months ended September 30, 2016 and 2015:

Three Months
Ended
September 30,

	2016	2015
Oil	\$41.97	\$44.17
Natural Gas	\$2.39	\$2.43
Natural gas liquids	\$12.56	\$8.66

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The decrease in average prices received during the three months ended September 30, 2016 was partially offset by a 9.4% increase in combined volumes sold by our operators as compared to the three months ended September 30, 2015.

	Change in prices	Production volumes ⁽¹⁾	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	\$ (2.20)	430,732	\$ (947)
Natural gas liquids	3.90	92,221	360
Natural gas	(0.04)	315,030	(13)
Total income due to change in price			\$ (600)

	Change in production volumes ⁽¹⁾	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	38,975	\$ 44.17	\$ 1,718
Natural gas liquids	10,882	8.66	94
Natural gas	(1,293)	2.43	(3)
Total income due to change in production volumes			1,809
Total change in income			\$ 1,209

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas.

General and Administrative Expenses

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 three months ended September 30, 2016 and 2015, we incurred general and administrative expenses of \$1.2 million and \$1.6 million, respectively.

Net Interest Expense

The net interest expense for the three months ended September 30, 2016 and 2015 reflects the interest incurred under our credit agreement. Net interest expense for the three months ended September 30, 2016 and 2015 was \$0.7 million and \$0.4 million, respectively.

Comparison of the Nine Months Ended September 30, 2016 and 2015

Royalty Income

Our royalty income for the nine months ended September 30, 2016 and 2015 was \$50.9 million and \$54.9 million, respectively. Our income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

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The following table summarizes the average amounts received by our operators for the nine months ended September 30, 2016 and 2015:

	Nine Months Ended September 30, 2016 2015	
Oil	\$37.64	\$47.10
Natural Gas	\$1.89	\$2.39
Natural gas liquids	\$11.25	\$10.44

The decrease in average prices received during the nine months ended September 30, 2016 was partially offset by a 16.0% increase in combined volumes sold by our operators as compared to the nine months ended September 30, 2015.

	Change in prices	Production volumes ⁽¹⁾	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	\$ (9.46)	1,236,003	\$ (11,693)
Natural gas liquids	0.81	221,582	179
Natural gas	(0.50)	1,008,745	(504)
Total income due to change in price			\$ (12,018)

	Change in production volumes ⁽¹⁾	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	150,010	\$ 47.10	\$ 7,065
Natural gas liquids	35,287	10.44	368
Natural gas	233,300	2.39	558
Total income due to change in production volumes			7,991
Total change in income			\$ (4,027)

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas.

Impairment

During the nine months ended September 30, 2016, we recorded an impairment of oil and natural gas interests of \$47.5 million as a result of the significant decline in commodity prices, which resulted in a reduction of the discounted present value of our proved oil and natural gas reserves. We did not record an impairment during the same period in 2015.

General and Administrative Expenses

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 nine months ended September 30, 2016 and 2015, we incurred general and administrative expenses of \$4.1 million and \$4.5 million, respectively.

Net Interest Expense

The net interest expense for the nine months ended September 30, 2016 and 2015 reflects the interest incurred under our credit agreement. Net interest expense for the nine months ended September 30, 2016 and 2015 was \$1.5 million and \$0.7 million, respectively.

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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, non-cash unit-based compensation, depletion expense and impairment 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.

	Three Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
	2016	2015	2016	2015
	(In thousands)			
Net income (loss)	\$10,202	\$6,355	\$(27,153)	\$19,482
Interest expense	658	358	1,544	733
Non-cash unit-based compensation expense	1,044	1,077	2,974	2,956
Depletion	6,751	8,737	21,485	26,587
Impairment	—	—	47,469	—
Adjusted EBITDA	\$18,655	\$16,527	\$46,319	\$49,758

Liquidity and Capital Resources

Overview

Our primary sources of liquidity have been cash flows from operations, equity offerings and borrowings under our credit agreement, and our primary uses of cash have been, and are expected to continue to be, distributions to our unitholders and replacement and growth capital expenditures, including the acquisition of oil and natural gas interests. Our ability to generate cash is subject to a number of factors, some of which are beyond our control, including commodity prices and general economic, financial, competitive, legislative, regulatory and other factors, including weather.

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.

On October 25, 2016, the board of directors of the General Partner approved a cash distribution for the third quarter of 2016 of \$0.207 per common unit, payable on November 18, 2016, to unitholders of record at the close of business on November 11, 2016.

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

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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.

August 2016 Public Offering

In August 2016, we completed an underwritten public offering of 8,050,000 common units, which included 1,050,000 common units issued pursuant to an option to purchase additional common units granted to the underwriter. In this offering, Diamondback purchased 2,000,000 common units from the underwriter at the price per common unit paid by the underwriter to us. We received net proceeds from this offering of approximately \$125.1 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we used to fund the purchase price for the August acquisition described under the heading “–Production and Operational Update–Recent Acquisitions” and repaid outstanding borrowings under our revolving credit facility.

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. On November 13, 2015, the borrowing base was increased from \$175.0 million to \$200.0 million. In connection with our spring 2016 redetermination, our borrowing base was set at \$175.0 million due to a decline in pricing. On August 5, 2016, we repaid \$78.0 million of our outstanding borrowings with a portion of the proceeds from our August 2016 public offering of common units and, as of September 30, 2016, we had \$54.5 million in outstanding borrowings under the credit agreement, with a weighted average interest rate of 2.28%. In connection with our fall 2016 redetermination, the agent lender under the credit agreement has recommended that our borrowing base be increased to \$275.0 million.

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 repaid (a) to the extent that 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 assets 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
	Not less than 1.0 to 1.0

Ratio of current
assets to liabilities,
as defined in the
credit agreement

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 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.

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Cash Flows

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

Nine Months
Ended September
30,
2016 2015

(in thousands)

Cash Flow Data:

Net cash flows provided by operating activities	\$46,554	\$45,973
Net cash flows used in investing activities	(137,786)	(32,220)
Net cash flows provided by (used in) financing activities	98,451	(23,912)
Net increase (decrease) in cash	\$7,219	\$(10,159)

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.

Investing Activities

Net cash used in investing activities was \$137.8 million and \$32.2 million during the nine months ended September 30, 2016 and 2015, respectively, related to acquisitions of royalty interests.

Financing Activities

Net cash provided by financing activities was \$98.5 million during the nine months ended September 30, 2016, primarily related to \$20.0 million of net borrowings under our revolving credit agreement and net proceeds of \$125.1 million from our public offering of common units partially offset by \$46.7 million of distributions to our unitholders during the period. Net cash used in financing activities was \$23.9 million during the nine months ended September 30, 2015, primarily related to \$52.6 million of distributions to our unitholders during that period, after giving effect to \$29.0 million of proceeds from borrowings under our credit facility.

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, 2015.

Critical Accounting Policies

There have been no changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2015.

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 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.

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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 two years, and we expect this volatility to continue in the future. The prices that our operators receive for production depend on many factors outside of our or their control.

Credit Risk

We are subject to risk resulting from the concentration of royalty income in producing oil and natural gas interests and receivables with several significant purchasers. For the nine months ended September 30, 2016, two purchasers accounted for more than 10% of our royalty income: Shell Trading (US) Company (63%) and RSP Permian LLC (28%). For the nine months ended September 30, 2015, two purchasers accounted for more than 10% of our royalty income: Shell Trading (US) Company (68%) and RSP Permian LLC (26%). 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 0.50% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. We entered into this credit agreement on July 8, 2014, and as of September 30, 2016, we had \$54.5 million in outstanding borrowings with a weighted average rate of 2.28%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately \$0.5 million based on the \$54.5 million outstanding in the aggregate under our credit agreement on September 30, 2016.

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.

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As of September 30, 2016, 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 September 30, 2016, 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 September 30, 2016 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. See Note 10. “Commitments and Contingencies–Litigation” to our financial statements.

ITEM 1A. RISK FACTORS

Our business faces many risks. Any of the risks discussed in this report 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 materially impair our business operations, financial condition or future results.

In addition to the information set forth in this report, 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, 2015 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, 2015.

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	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).
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.

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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 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: November 8, 2016 By: /s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer

Date: November 8, 2016 By: /s/ Teresa L. Dick
Teresa L. Dick
Chief Financial Officer