Viper Energy Partners LP
Form 10-Q
October 25, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ýQUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2017
OR
o TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934

Commission File Number 001-36505

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

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

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

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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check One):

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

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

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

As of October 20, 2017, 113,882,045 common limited partner units of the registrant were outstanding.

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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.
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.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
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.
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.
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.
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, including our recent and pending acquisitions;
- general economic, business or industry conditions;
- competition in the oil and natural gas industry;
- the ability of our operators to obtain capital or financing needed for development and exploration operations;
- title defects in the properties in which we invest;
- 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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Viper Energy Partners LP
Consolidated Balance Sheets
(Unaudited)

	September 30, 2017	December 31, 2016
	(In thousands, except unit amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$4,438	$9,213
Restricted cash	—	500
Royalty income receivable	17,199	10,043
Royalty income receivable—related party	3,646	3,470
Other current assets	147	187
Total current assets	25,430	23,413
Property and equipment:		
Oil and natural gas interests, full cost method of accounting ($487,899 and $252,232 excluded from depletion at September 30, 2017 and December 31, 2016, respectively)	1,065,392	760,818
Accumulated depletion and impairment	(177,534)	(148,948)
Oil and natural gas interests, net	887,858	611,870
Other assets	34,929	35,266
Total assets	$948,217	$670,549
Liabilities and Unitholders’ Equity		
Current liabilities:		
Accounts payable	$110	$1,780
Other accrued liabilities	2,747	371
Total current liabilities	2,857	2,151
Long-term debt	35,500	120,500
Total liabilities	38,357	122,651
Commitments and contingencies (Note 10)		
Unitholders’ equity:		
Common units (113,882,045 units issued and outstanding as of September 30, 2017 and 87,800,356 units issued and outstanding as of December 31, 2016)	909,860	547,898
Total unitholders’ equity	909,860	547,898
Total liabilities and unitholders’ equity	$948,217	$670,549

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands, except per unit amounts)			
Operating income:				
Royalty income	$42,211	$19,992	$110,194	$50,914
Lease bonus	322	5	2,613	309
Total operating income	42,533	19,997	112,807	51,223
Costs and expenses:				
Production and ad valorem taxes	2,825	1,429	7,668	4,134
Gathering and transportation	205	70	492	247
Depletion	11,068	6,751	28,587	21,485
Impairment	—	—	—	47,469
General and administrative expenses	1,368	1,153	5,064	4,109
Total costs and expenses	15,466	9,403	41,811	77,444
Income (loss) from operations	27,067	10,594	70,996	(26,221)
Other income (expense):				
Interest expense	(859)	(658)	(2,114)	(1,544)
Other income	399	266	526	612
Total other income (expense), net	(460)	(392)	(1,588)	(932)
Net income (loss)	$26,607	$10,202	$69,408	$(27,153)
Net income attributable to common limited partners per unit:				
Basic and Diluted	$0.24	$0.12	$0.69	$(0.33)
Weighted average number of limited partner units outstanding:				
Basic	110,377	84,996	101,095	81,496
Diluted	110,424	85,003	101,143	81,496

See accompanying notes to consolidated financial statements.

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Viper Energy Partners LP
Consolidated Statements of Unitholders' Equity
(Unaudited)

	Limited Partners Common	
	Units	Amount
		(In thousands)
Balance at December 31, 2015	79,726	$ 495,144
Net proceeds from the issuance of common units - public	6,050	93,564
Net proceeds from the issuance of common units - Diamondback	2,000	31,200
Unit-based compensation	24	2,974
Distributions to public		(6,397)
Distributions to Diamondback		(40,253)
Net loss		(27,153)
Balance at September 30, 2016	87,800	$ 549,079
Balance at December 31, 2016	87,800	$ 547,898
Net proceeds from the issuance of common units - public	25,175	369,896
Net proceeds from the issuance of common units - Diamondback	700	10,067
Common units issued for acquisition	175	3,050
Unit-based compensation	32	2,039
Distributions to public		(27,640)
Distributions to Diamondback		(64,858)
Net income		69,408
Balance at September 30, 2017	113,882	$ 909,860

See accompanying notes to consolidated financial statements.

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

	Nine Months Ended September 30, 2017	2016
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 69,408	$ (27,153)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion	28,587	21,485
Impairment	—	47,469
Amortization of debt issuance costs	434	280
Non-cash unit-based compensation	2,039	2,974
Changes in operating assets and liabilities:		
Restricted cash	500	—
Royalty income receivable	(7,156)	(549)
Royalty income receivable—related party	(176)	—
Accounts payable—related party	—	(4)
Accounts payable and other accrued liabilities	367	1,707
Other current assets	54	345
Net cash provided by operating activities	94,057	46,554
Cash flows from investing activities:		
Acquisition of mineral interests	(301,133)	(137,786)
Net cash used in investing activities	(301,133)	(137,786)
Cash flows from financing activities:		
Proceeds from borrowings under credit facility	220,500	98,000
Repayment on credit facility	(305,500)	(78,000)
Debt issuance costs	(180)	(35)
Proceeds from public offerings	380,412	125,580
Public offering costs	(433)	(444)

Distributions to partners	(92,498		)	(46,650		)
Net cash provided by financing activities	202,301			98,451		
Net increase (decrease) in cash	(4,775		)	7,219		
Cash and cash equivalents at beginning of period	9,213			539		
Cash and cash equivalents at end of period	$	4,438		$	7,758	
Supplemental disclosure of cash flow information:						
Interest paid, net of capitalized interest	$	1,781		$	1,251	

See accompanying notes to consolidated financial statements.

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Viper Energy Partners LP (the “Partnership”) is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global 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.

As of September 30, 2017, Viper Energy Partners GP LLC (the “General Partner”), held a 100% non-economic general partner interest in the Partnership and Diamondback had an approximate 64% limited partner interest in the Partnership. Diamondback owns and controls the General Partner.

Basis of Presentation

The accompanying consolidated financial statements and related notes thereto were prepared in conformity with 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, 2016, 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 May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing and 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, 2017, early application permitted for annual reporting period beginning after December 31, 2016. 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 of this standard; however, the Partnership has reviewed its various contracts and has not identified any revenue that would be materially impacted and therefore does not expect the adoption of this standard to have a material impact on the Partnership’s financial position, results of operations and liquidity. The Partnership anticipates using the modified retrospective adoption.

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 believes the primary impact of adopting this standard will be the recognition of assets and liabilities on the balance sheet for current operating leases. The Partnership is still evaluating the impact of this standard.

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 was effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. The Partnership prospectively adopted this standard effective January 1, 2017. The Partnership elected to account for forfeitures as they occur as a result of adopting this standard.

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, non-cash 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.

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

In November 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-18, "Statement of Cash Flows - Restricted Cash". This update affects entities that have restricted cash or restricted cash equivalents. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted, including adoption in an interim period. This update will be applied retrospectively. The Partnership does not expect the adoption of this standard to have a material impact on the Partnership's financial position, results of operations and liquidity.

In January 2017, the Financial Accounting Standards Board issued Accounting Standards Update 2017-01, "Business Combinations - Clarifying the Definition of a Business". This update apples to all entities that must determine whether they acquired or sold a business. This update provides a screen to determine when a set is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2017, including interim periods within those fiscal years. This update should be applied prospectively on or after the effective date. This update is not expected to have a material impact on the Partnership's financial statements or results of operations. The adoption of this update will change the process that the Partnership uses to evaluate whether the Partnership has acquired a business or an asset. This update will be applied prospectively and will not have an effect on prior acquisitions.

3. ACQUISITIONS

During the nine months ended September 30, 2017, the Partnership acquired mineral interests underlying 2,769 net royalty acres for an aggregate purchase price of approximately $304.6 million and, as of September 30, 2017, had mineral interests underlying 9,173 net royalty acres. The Partnership funded these acquisitions primarily with borrowings under its revolving credit facility, with a portion of the net proceeds from its January and July 2017 offerings of common units and with the issuance of 174,513 common units to a seller in a private placement in May 2017.

4. OIL AND NATURAL GAS INTERESTS

Oil and natural gas interests include the following:

	September 30, 2017	December 31, 2016
	(in thousands)	
Oil and natural gas interests:		
Subject to depletion	$577,493	$508,586
Not subject to depletion	487,899	252,232
Gross oil and natural gas interests	1,065,392	760,818
Accumulated depletion and impairment	(177,534)	(148,948)
Oil and natural gas interests, net	$887,858	$611,870

Balance of acquisition costs not subject to depletion	
Incurred in 2017	$250,227
Incurred in 2016	$162,984
Incurred in 2015	$32,067
Incurred in 2014	$42,621
Total not subject to depletion	$487,899

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.

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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 was no impairment recorded for the nine months ended September 30, 2017. For 2016, 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, transfers of unevaluated properties and other factors will determine its actual ceiling test limitations and impairment analysis in future periods.

5. DEBT

Credit Agreement-Wells Fargo Bank

The Partnership is party to a secured revolving credit agreement, dated as of July 8, 2014, as amended, with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on 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, 2017, the borrowing base was set at $315.0 million and the Partnership had $35.5 million in outstanding borrowings 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 1.00% to 2.00% in the case of the alternative base rate and from 2.00% to 3.00% 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 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, 2017, the General Partner allocated $0.6 million and $1.8 million, respectively, to the Partnership. During the three and nine months ended September 30, 2016, 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. For the three and nine months ended September 30, 2017 and 2016, the Partnership did not pay any costs 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, 2017, Diamondback did not pay the Partnership any lease bonus payments. During the nine months ended September 30, 2017, Diamondback paid the Partnership $0.1 million in lease bonus payments to extend the term of two leases, reflecting an average bonus of $7,459 per acre. During the 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, respectively, 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. As of September 30, 2017, a total of 9,070,356 common units had 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, 2017, the Partnership incurred $0.5 million and $2.0 million of unit–based compensation.

Phantom Units

Under the LTIP, the board of directors of the General Partner is authorized to issue phantom units to eligible employees and non-employee directors. 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, 2017:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2016	21,048	$ 16.23
Granted	103,190	$ 16.79
Vested	(32,176)	$ 16.49
Unvested at September 30, 2017	92,062	$ 16.77

The aggregate fair value of phantom units that vested during the nine months ended September 30, 2017 was $0.5 million. As of September 30, 2017, the unrecognized compensation cost related to unvested phantom units was $1.4 million. Such cost is expected to be recognized over a weighted-average period of 1.3 years.

8. UNITHOLDERS' EQUITY AND PARTNERSHIP DISTRIBUTIONS

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

At September 30, 2017, the Partnership had a total of 113,882,045 common units issued and outstanding, of which 73,150,000 common units were owned by Diamondback, representing approximately 64% of the total Partnership common units outstanding.

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

	Common Units
Balance at December 31, 2016	87,800,356
Common units issued in public offerings	25,875,000
Common units vested and issued under the LTIP	32,176
Common units issued for acquisition	174,513

Balance at September 30, 2017	113,882,045

The board of directors of the General Partner has adopted a policy for the Partnership to distribute all available cash generated on a quarterly basis, beginning with the quarter ended September 30, 2014.

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

	Amount per Common Unit	Declaration Date	Unitholder Record Date	Payment Date
Q4 2016	$ 0.258	February 3, 2017	February 17, 2017	February 24, 2017
Q1 2017	$ 0.302	April 28, 2017	May 18, 2017	May 25, 2017
Q2 2017	$ 0.332	July 28, 2017	August 17, 2017	August 24, 2017

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.

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, 2017 and 2016, 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—Unitholders' Equity 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,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands, except per unit amounts)			
Net income (loss) attributable to the period	26,607	10,202	69,408	(27,153)
Weighted average common units outstanding				
Basic weighted average common units outstanding	110,377	84,996	101,095	81,496
Effect of dilutive securities:				
Potential common units issuable	47	7	48	—
Diluted weighted average common units outstanding	110,424	85,003	101,143	81,496
Net income per common unit, basic	$0.24	$0.12	$0.69	$(0.33)
Net income per common unit, diluted	$0.24	$0.12	$0.69	$(0.33)

For the three months ended September 30, 2017 and 2016, there were 1,356 common units and 1,514,069 common units, respectively, and for the nine months ended September 30, 2017 and 2016, there were 43,414 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

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from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

11. SUBSEQUENT EVENTS

Cash Distribution

On October 16, 2017, the board of directors of the General Partner approved a cash distribution for the third quarter of 2017 of $0.337 per common unit, payable on November 14, 2017, to unitholders of record at the close of business on November 7, 2017.

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, 2016. 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, 2017, our general partner held a 100% non-economic general partner interest in us, and Diamondback had an approximate 64% limited partner interest in us. Diamondback also owns and controls our general partner.

In January 2017, we completed an underwritten public offering of 9,775,000 common units, which included 1,275,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. We received net proceeds from this offering of approximately $147.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which $120.5 million was used to repay the outstanding borrowings under our revolving credit agreement and the balance was used for general partnership purposes, which included additional acquisitions.
In July 2017, we completed an underwritten public offering of 16,100,000 common units, which included 2,100,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Diamondback purchased 700,000 common units, an affiliate of our general partner purchased 3,000,000 common units and certain officers and directors of Diamondback and our general partner purchased an aggregate of 114,000 common units, in each case directly from the underwriters. Following this offering, Diamondback had an approximate 64% limited partner interest in us. We received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which we used $152.8 million to repay all of the then-outstanding borrowings under our revolving credit facility and the balance was used to fund a portion of the purchase price for acquisitions and for general partnership purposes, which included additional acquisitions.

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,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Royalty income				
Oil sales	85 %	90 %	88 %	91 %
Natural gas sales	7 %	4 %	6 %	4 %
Natural gas liquid sales	8 %	6 %	6 %	5 %
	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 2016, West Texas Intermediate posted prices ranged from $26.19 to $54.01 per Bbl and the Henry Hub spot market price of natural gas ranged from $1.49 to $3.80 per MMBtu. During the first nine months of 2017, West Texas Intermediate posted prices ranged from $42.48 to $54.48 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. On September 29, 2017, the West Texas Intermediate posted price for crude oil was $51.67 per Bbl and the Henry Hub spot market price of natural gas was $2.94 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 redetermined at the discretion of our lenders.

Recent Acquisitions

During the third quarter of 2017, we acquired 1,677 net royalty acres for an aggregate purchase price of $178.9 million, subject to post-closing adjustments, bringing our total mineral interests to 9,173 net royalty acres as of September 30, 2017.

Production and Operational Update

Our average daily production during the third quarter of 2017 was 12,611 BOE/d (68% oil), and our operators received an average of $45.33 per Bbl of oil, $19.10 per Bbl of natural gas liquids and $2.55 per Mcf of natural gas, for an average realized price of $36.38 per BOE.

During the third quarter of 2017, the operators of our Spanish Trail mineral interests brought online nine gross horizontal wells with an average royalty interest of 12.2%, consisting of three Lower Spraberry, four Wolfcamp A, one Wolfcamp B and one Middle Spraberry wells. As of September 30, 2017, there were approximately 24 horizontal wells with an average royalty interest of 21.2% 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, Pecos, Ward, Martin, Howard and Glasscock counties. As of September 30, 2017, we had 736 vertical wells and 478 horizontal wells producing on our acreage. As of October 20, 2017, there were 22 active rigs and 319 active horizontal drilling permits on our acreage. We intend to continue to be active in acquiring mineral interests with near term visibility and accretive cash flow growth.

We declared a cash dividend for the third quarter of 2017 of $0.337 per common unit, payable on November 14, 2017, to unitholders of record at the close of business on November 7, 2017.

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.

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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. Diamondback does not expect any Texas margin tax to be due for the nine months ended September 30, 2017 or 2016.

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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 September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(unaudited, in thousands, except production data)			
Operating Results:				
Operating income:				
Royalty income	$42,211	$19,992	$110,194	$50,914
Lease bonus	322	5	2,613	309
Total operating income	42,533	19,997	112,807	51,223
Costs and expenses:				
Production and ad valorem taxes	2,825	1,429	7,668	4,134
Gathering and transportation	205	70	492	247
Depletion	11,068	6,751	28,587	21,485
Impairment	—	—	—	47,469
General and administrative expenses	1,368	1,153	5,064	4,109
Total costs and expenses	15,466	9,403	41,811	77,444
Income (loss) from operations	27,067	10,594	70,996	(26,221)
Other income (expense):				
Interest expense	(859)	(658)	(2,114)	(1,544)
Other income	399	266	526	612
Total other income (expense), net	(460)	(392)	(1,588)	(932)
Net income (loss)	$26,607	$10,202	$69,408	$(27,153)
Production Data:				
Oil (Bbls)	794,375	430,732	2,077,570	1,236,003
Natural gas (Mcf)	1,236,349	315,030	2,460,535	1,008,745
Natural gas liquids (Bbls)	159,806	92,221	393,913	221,582
Combined volumes (BOE)	1,160,239	575,458	2,881,572	1,625,709
Daily combined volumes (BOE/d)	12,611	6,255	10,555	5,933
% Oil	68 %	75 %	72 %	76 %
Average sales prices:				
Oil, realized ($/Bbl)	$45.33	$41.97	$46.51	$37.64
Natural gas realized ($/Mcf)	2.55	2.39	2.62	1.89
Natural gas liquids ($/Bbl)	19.10	12.56	18.07	11.25
Average price realized ($/BOE)	36.38	34.74	38.24	31.32
Average Costs ($/BOE)				
Production and ad valorem taxes	$2.43	$2.48	$2.66	$2.54
Gathering and transportation expense	0.18	0.12	0.17	0.15
General and administrative - cash component	0.75	0.19	1.05	0.70
Total operating expense - cash	$3.36	$2.79	$3.88	$3.39

General and administrative - non-cash component	$0.43	$1.81	$0.71	$1.83
Interest expense	0.74	1.14	0.73	0.95
Depletion	9.54	11.73	9.92	13.22

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Comparison of the Three Months Ended September 30, 2017 and 2016

Royalty Income

Our royalty income for the three months ended September 30, 2017 and 2016 was $42.2 million and $20.0 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

In addition to the increase in average prices received during the three months ended September 30, 2017, we also benefited from a 101.6% increase in combined volumes sold by our operators as compared to the three months ended September 30, 2016.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 3.36	794,375	$ 2,669
Natural gas liquids	6.54	159,806	1,045
Natural gas	0.16	1,236,349	198
Total income due to change in price			$ 3,912

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	363,643	$ 41.97	$ 15,256
Natural gas liquids	67,585	12.56	849
Natural gas	921,319	2.39	2,202
Total income due to change in production volumes			18,307
Total change in income			$ 22,219

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

Lease Bonus Income

Lease bonus income increased by $0.3 million for the three months ended September 30, 2017 as compared to the three months ended September 30, 2016. During the three months ended September 30, 2017, we received $0.3 million in lease bonus payments to extend the term of one lease, reflecting an average bonus of $10,000 per acre.

General and Administrative Expenses

The general and administrative expenses primarily reflect costs associated with us being a publicly traded limited partnership, unit-based compensation and the amounts reimbursed to our general partner under our partnership agreement. For the three months ended September 30, 2017 and 2016, we incurred general and administrative expenses of $1.4 million and $1.2 million, respectively. The increase of $0.2 million during the three months ended September 30, 2017 was primarily due to the reimbursement of expenses to the General Partner under the Partnership Agreement, partially offset by a decrease in unit-based compensation expense.

Net Interest Expense

The net interest expense for the three months ended September 30, 2017 and 2016 reflects the interest incurred under our credit agreement. Net interest expense for the three months ended September 30, 2017 and 2016 was $0.9 million and $0.7 million, respectively. The increase of $0.2 million was due to a higher interest rate and increased borrowings during the three months ended September 30, 2017 as compared to the three months ended September 30, 2016.

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Comparison of the Nine Months Ended September 30, 2017 and 2016

Royalty Income

Our royalty income for the nine months ended September 30, 2017 and 2016 was $110.2 million and $50.9 million, respectively. Our royalty income is a function of oil, natural gas liquids and natural gas production volumes sold and average prices received for those volumes.

In addition to the increase in average prices received during the nine months ended September 30, 2017, we also benefited from a 77.3% increase in combined volumes sold by our operators as compared to the nine months ended September 30, 2016.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$ 8.87	2,077,570	$ 18,433
Natural gas liquids	6.82	393,913	2,686
Natural gas	0.73	2,460,535	1,796
Total income due to change in price			$ 22,915

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	841,567	$ 37.64	$ 31,682
Natural gas liquids	172,331	11.25	1,939
Natural gas	1,451,790	1.89	2,744
Total income due to change in production volumes			36,365
Total change in income			$ 59,280

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

Lease Bonus Income

Lease bonus income increased by $2.3 million for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016. During the nine months ended September 30, 2017, we received $2.6 million in lease bonus payments to extend the term of six leases, reflecting an average bonus of $3,333 per acre.

Impairment of Oil and Gas Properties

During the nine months ended September 30, 2016, we recorded an impairment of oil and gas properties of $47.5 million as a result of the significant decline in commodity prices. No impairment was recorded for the nine months ended September 30, 2017.

General and Administrative Expenses

For the nine months ended September 30, 2017 and 2016, we incurred general and administrative expenses of $5.1 million and $4.1 million, respectively. The increase of $1.0 million during the nine months ended September 30, 2017 was primarily due to the reimbursement of expenses to the General Partner under the Partnership Agreement, partially offset by a decrease in unit-based compensation expense.

Net Interest Expense

The net interest expense for the nine months ended September 30, 2017 and 2016 reflects the interest incurred under our credit agreement. Net interest expense for the nine months ended September 30, 2017 and 2016 was $2.1 million and $1.5 million, respectively. The increase of $0.6 million was due to a higher interest rate and increased borrowings during the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016.

Adjusted EBITDA

Adjusted EBITDA is a supplemental non-GAAP financial measure used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Adjusted EBITDA is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations 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 expense, depletion expense and impairment expense. Adjusted EBITDA is not a measure of net income (loss) as determined by GAAP. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure, as well as historic costs of depreciable assets, none of which are components of Adjusted EBITDA.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, 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,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands)			
Net income (loss)	$26,607	$10,202	$69,408	$(27,153)
Interest expense	859	658	2,114	1,544
Non-cash unit-based compensation expense	503	1,044	2,039	2,974
Depletion	11,068	6,751	28,587	21,485
Impairment	—	—	—	47,469
Adjusted EBITDA	$39,037	$18,655	$102,148	$46,319

Liquidity and Capital Resources

Overview

Our primary sources of liquidity have been cash flows from operations, proceeds from 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. We intend to finance potential future acquisitions through a combination of cash on hand, borrowings under our credit agreement and, subject to market conditions and other factors, proceeds from one or more capital market transactions, which may include debt or equity offerings. 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 16, 2017, the board of directors of the General Partner approved a cash distribution for the third quarter of 2017 of $0.337 per common unit, payable on November 14, 2017, to unitholders of record at the close of business on November 7, 2017.

Cash distributions are made to the common unitholders of record on the applicable record date, generally within 60 days after the end of each quarter. Available cash for each quarter is determined by the board of directors of our general partner following the end of such quarter. Available cash for each quarter generally equals Adjusted EBITDA reduced for cash needed for debt service and other contractual obligations and fixed charges and reserves for future operating or capital needs that the board of directors of our general partner deems necessary or appropriate, if any.

January 2017 Public Offering

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

July 2017 Public Offering

In July 2017, we completed an underwritten public offering of 16,100,000 common units, which included 2,100,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. We received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commission and estimated offering expenses, of which $152.8 million was used to repay all of the then-outstanding borrowings under our revolving credit facility, and the balance was used to fund a portion of the purchase price for acquisitions and for general corporate purposes, which included additional acquisitions.

Our Credit Agreement

We are party to a $500.0 million secured revolving credit agreement, dated as of July 8, 2014, as amended, with Wells Fargo as the administrative agent, sole book runner and lead arranger, and certain other lenders party thereto. The credit agreement matures on July 8, 2019. As of September 30, 2017, the borrowing base was set at $315.0 million and we had $35.5 million in outstanding borrowings under our credit agreement.

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 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 1.00% to 2.00% in the case of the alternative base rate and from 2.00% to 3.00% 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
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

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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.

Cash Flows

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

	Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
Cash Flow Data:		
Net cash flows provided by operating activities	$94,057	$46,554
Net cash flows used in investing activities	(301,133)	(137,786)
Net cash flows provided by financing activities	202,301	98,451
Net increase (decrease) in cash	$(4,775)	$7,219

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 $301.1 million and $137.8 million during the nine months ended September 30, 2017 and 2016, respectively, and related to acquisitions of mineral interests.

Financing Activities

Net cash provided by financing activities was $202.3 million during the nine months ended September 30, 2017, primarily related to net proceeds of $380.0 million from our public offerings of common units, partially offset by the repayment of $85.0 million net of borrowings under our revolving credit agreement and distributions of $92.5 million to our unitholders during the period. 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 that period.

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, 2016.

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, 2016.

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.

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, 2017, two purchasers each accounted for more than 10% of our royalty income: Shell Trading (US) Company (48%) and RSP Permian LLC (23%). For the nine months ended September 30, 2016, two purchasers each accounted for more than 10% of our royalty income: Shell Trading (US) Company (63%) and RSP Permian LLC (28%). We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our credit agreement. The terms of our credit agreement provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.50% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 1.00% to 2.00% in the case of the alternative base rate and from 2.00% to 3.00% 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, as subsequently amended, and as of September 30, 2017, we had $35.5 million in outstanding borrowings. Our weighted average interest rate on borrowings under our revolving credit facility was 3.24%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $0.4 million based on the $35.5 million outstanding in the aggregate under our credit agreement.

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 September 30, 2017, an evaluation was performed under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of our general partner, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon the evaluation, the Chief Executive Officer and Chief Financial Officer of our general partner have concluded that as of September 30, 2017, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting. There have not been any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

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 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, 2016 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, 2016.

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 between 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).
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 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:	October 25, 2017	By:	/s/ Travis D. Stice Travis D. Stice Chief Executive Officer
Date:	October 25, 2017	By:	/s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer