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, 2017

OR

o **TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 001-35700

Diamondback Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

Delaware	**45-4502447**
(State or Other Jurisdiction of Incorporation or Organization)	**(IRS Employer Identification Number)**
500 West Texas, Suite 1200 **Midland, Texas**	**79701**
(Address of Principal Executive Offices)	**(Zip Code)**

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

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the past 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ 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, 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	☒	Accelerated Filer	o
Non-Accelerated Filer	o	Smaller Reporting Company	o
		Emerging Growth Company	o

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. o

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 1, 2017, 98,167,289 shares of the registrant's common stock were outstanding.

DIAMONDBACK ENERGY, INC.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2017

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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.
Finding and development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
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.
Plugging and abandonment	Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
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.
Spacing	The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.
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.

GLOSSARY OF CERTAIN OTHER TERMS

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

Company	Diamondback Energy, Inc., a Delaware corporation.
Equity Plan	The Company’s Equity Incentive Plan.
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.
NYMEX	New York Mercantile Exchange.
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 Viper Offering.
SEC	United States Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
2024 Senior Notes	The Company’s 4.750% senior unsecured notes due 2024 in the aggregate principal amount of $500 million.
2025 Senior Notes	The Company’s 5.375% senior unsecured notes due 2025 in the aggregate principal amount of $500 million.
Senior Notes	The 2024 Senior Notes and the 2025 Senior Notes.
Viper LTIP	Viper Energy Partners LP Long Term Incentive Plan.
Viper Offering	The Partnerships’ initial public offering.
Wells Fargo	Wells Fargo Bank, National Association.

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 and detailed under *Part II, Item 1A. Risk Factors* in this report and our Annual Report on Form 10–K for the year ended December 31, 2016 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:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- acquisitions;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

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.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(Unaudited)

	September 30, 2017	December 31, 2016
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 30,205	$ 1,666,574
Restricted cash	—	500
Accounts receivable:		
Joint interest and other	49,715	49,476
Oil and natural gas sales	103,963	70,349
Related party	14	297
Inventories	4,834	1,983
Derivative instruments	1,614	—
Prepaid expenses and other	3,509	2,987
Total current assets	193,854	1,792,166
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($4,197,159 and $1,730,519 excluded from amortization at September 30, 2017 and December 31, 2016, respectively)	8,869,286	5,160,261
Midstream assets	156,379	8,362
Other property, equipment and land	79,738	58,290
Accumulated depletion, depreciation, amortization and impairment	(2,056,796)	(1,836,056)
Net property and equipment	7,048,607	3,390,857
Funds held in escrow	—	121,391
Derivative instruments	—	709
Other assets	45,107	44,557
Total assets	$ 7,287,568	$ 5,349,680
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$ 74,700	$ 47,648
Accounts payable-related party	—	1
Accrued capital expenditures	189,455	60,350
Other accrued liabilities	90,397	55,330
Revenues and royalties payable	53,062	23,405
Derivative instruments	10,003	22,608
Total current liabilities	417,617	209,342
Long-term debt	1,256,388	1,105,912
Derivative instruments	4,145	—
Asset retirement obligations	19,982	16,134
Deferred income taxes	3,313	—
Total liabilities	1,701,445	1,331,388
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 98,167,289 issued and outstanding at September 30, 2017; 90,143,934 issued and outstanding at December 31, 2016	982	901
Additional paid-in capital	5,049,210	4,215,955
Accumulated deficit	(151,692)	(519,394)
Total Diamondback Energy, Inc. stockholders' equity	4,898,500	3,697,462
Non-controlling interest	687,623	320,830
Total equity	5,586,123	4,018,292
Total liabilities and equity	$ 7,287,568	$ 5,349,680

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(In thousands, except per share amounts)			
Revenues:				
Oil sales	$ 259,049	$ 126,353	$ 704,007	$ 306,698
Natural gas sales	14,922	6,334	37,537	14,465
Natural gas liquid sales	25,266	9,444	57,625	20,932
Lease bonus	322	—	2,507	—
Midstream services	1,694	—	4,241	—
Total revenues	301,253	142,131	805,917	342,095
Costs and expenses:				
Lease operating expenses	32,498	22,180	88,113	59,080
Production and ad valorem taxes	18,371	9,123	49,975	25,244
Gathering and transportation	3,476	2,843	9,110	8,064
Midstream services	4,445	—	7,127	—
Depreciation, depletion and amortization	87,579	44,746	221,681	126,686
Impairment of oil and natural gas properties	—	46,368	—	245,536
General and administrative expenses (including non-cash equity-based compensation, net of capitalized amounts, of $6,187 and $6,265 for the three months ended September 30, 2017 and 2016, respectively, and $19,418 and $20,643 for the nine months ended September 30, 2017 and 2016, respectively)	11,888	9,908	37,524	32,411
Asset retirement obligation accretion	357	270	1,030	770
Total costs and expenses	158,614	135,438	414,560	497,791
Income (loss) from operations	142,639	6,693	391,357	(155,696)
Other income (expense):				
Interest expense	(9,192)	(10,234)	(29,662)	(30,266)
Other income	3	907	9,472	1,647
Gain (loss) on derivative instruments, net	(50,645)	2,034	20,376	(8,665)
Total other income (expense), net	(59,834)	(7,293)	186	(37,284)
Income (loss) before income taxes	82,805	(600)	391,543	(192,980)
Provision for income taxes	857	—	4,393	368
Net income (loss)	81,948	(600)	387,150	(193,348)
Net income (loss) attributable to non-controlling interest	8,924	1,630	19,448	(2,716)
Net income (loss) attributable to Diamondback Energy, Inc.	$ 73,024	$ (2,230)	$ 367,702	$ (190,632)
Earnings per common share:				
Basic	$ 0.74	$ (0.03)	$ 3.81	$ (2.60)
Diluted	$ 0.74	$ (0.03)	$ 3.80	$ (2.60)
Weighted average common shares outstanding:				
Basic	98,144	77,167	96,491	73,318
Diluted	98,369	77,167	96,752	73,318

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Stockholders' Equity
(Unaudited)

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	Shares	Amount				
	(In thousands)					
Balance December 31, 2015	66,797	$ 668	$ 2,229,664	$ (354,360)	$ 233,001	$ 2,108,973
Net proceeds from issuance of common units - Viper Energy Partners LP		—	—	—	93,564	93,564
Unit-based compensation		—	—	—	2,974	2,974
Stock-based compensation		—	23,193	—	—	23,193
Distribution to non-controlling interest		—	—	—	(6,397)	(6,397)
Common shares issued in public offering, net of offering costs	10,925	109	805,728	—	—	805,837
Exercise of stock options and vesting of restricted stock units	344	4	495	—	—	499
Net loss		—	—	(190,632)	(2,716)	(193,348)
Balance September 30, 2016	78,066	$ 781	$ 3,059,080	$ (544,992)	$ 320,426	$ 2,835,295
Balance December 31, 2016	90,144	$ 901	$ 4,215,955	$ (519,394)	$ 320,830	$ 4,018,292
Net proceeds from issuance of common units - Viper Energy Partners LP		—	—	—	369,896	369,896
Unit-based compensation		—	—	—	2,039	2,039
Common units issued for acquisition		—	—	—	3,050	3,050
Stock-based compensation		—	23,790	—	—	23,790
Distribution to non-controlling interest		—	—	—	(27,640)	(27,640)
Common shares issued in public offering, net of offering costs		—	14	—	—	14
Common shares issued for acquisition	7,686	77	809,096	—	—	809,173
Exercise of stock options and vesting of restricted stock units	337	4	355	—	—	359
Net income		—	—	367,702	19,448	387,150
Balance September 30, 2017	98,167	$ 982	$ 5,049,210	$ (151,692)	$ 687,623	$ 5,586,123

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ 387,150	$ (193,348)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Provision for deferred income taxes	3,313	—
Impairment of oil and natural gas properties	—	245,536
Asset retirement obligation accretion	1,030	770
Depreciation, depletion and amortization	221,681	126,686
Amortization of debt issuance costs	2,828	2,023
Change in fair value of derivative instruments	(9,365)	12,858
Income from equity investment	(309)	(65)
Equity-based compensation expense	19,418	20,643
Gain (loss) on sale of assets, net	(386)	37
Changes in operating assets and liabilities:		
Accounts receivable	(23,422)	(7,600)
Accounts receivable-related party	283	1,578
Restricted cash	500	—
Inventories	(2,700)	(241)
Prepaid expenses and other	(9,242)	(2,064)
Accounts payable and accrued liabilities	18,305	10,590
Accounts payable and accrued liabilities-related party	(2)	(216)
Accrued interest	(1,738)	8,564
Income tax payable	1,017	—
Revenues and royalties payable	29,657	595
Net cash provided by operating activities	638,018	226,346
Cash flows from investing activities:		
Additions to oil and natural gas properties	(531,489)	(241,609)
Additions to oil and natural gas properties-related party	—	(637)
Additions to midstream assets	(22,491)	(1,188)
Purchase of other property and equipment	(21,534)	(9,805)
Acquisition of leasehold interests	(1,892,864)	(591,785)
Acquisition of mineral interests	(370,855)	(137,782)
Acquisition of midstream assets	(50,279)	—
Proceeds from sale of assets	3,584	1,566
Funds held in escrow	121,391	—
Equity investments	(188)	(800)
Net cash used in investing activities	(2,764,725)	(982,040)
Cash flows from financing activities:		
Proceeds from borrowings under credit facility	533,000	98,000
Repayment under credit facility	(383,500)	(89,000)
Debt issuance costs	(1,714)	(128)
Public offering costs	(510)	(800)
Proceeds from public offerings	370,344	900,675
Proceeds from exercise of stock options	358	498
Distributions to non-controlling interest	(27,640)	(6,397)
Net cash provided by financing activities	490,338	902,848

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows - Continued
(Unaudited)

	Nine Months Ended September 30,	
	2017	**2016**
Net increase (decrease) in cash and cash equivalents	(1,636,369)	147,154
Cash and cash equivalents at beginning of period	1,666,574	20,115
Cash and cash equivalents at end of period	$ 30,205	$ 167,269
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$ 28,702	$ 19,845
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ 129,105	$ (12,130)
Capitalized stock-based compensation	$ 6,411	$ 5,525
Common stock issued for oil and natural gas properties	$ 809,173	$ —
Asset retirement obligations acquired	$ 2,411	$ 3,022

See accompanying notes to combined consolidated financial statements.

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc. (“Diamondback” or the “Company”), together with its subsidiaries, is an independent oil and gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Diamondback was incorporated in Delaware on December 30, 2011.

The wholly-owned subsidiaries of Diamondback, as of September 30, 2017, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company, and Rattler Midstream LLC (formerly known as White Fang Energy LLC), a Delaware limited liability company. The consolidated subsidiaries include these wholly-owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership (the “Partnership”), and the Partnership’s wholly-owned subsidiary Viper Energy Partners LLC, a Delaware limited liability company.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries after all significant intercompany balances and transactions have been eliminated upon consolidation.

The Partnership is consolidated in the financial statements of the Company. As of September 30, 2017, the Company owned approximately 64% of the common units of the Partnership. The Company’s wholly-owned subsidiary, Viper Energy Partners GP LLC, is the General Partner of the Partnership.

These financial statements have been prepared by the Company 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 Company 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 Company’s most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2016, which contains a summary of the Company’s significant accounting policies and other disclosures.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company’s consolidated 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 consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company’s disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company’s estimates. Any effects on the Company’s business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, equity-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

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. 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 Company plans to adopt the standard effective January 1, 2018 using the modified retrospective approach. The Company has reviewed its various contracts and is nearing completion of its evaluation of the impact of the new revenue standard and related interpretive guidance on its financial statements, accounting policies, internal controls, and disclosures. Based on assessments performed to date, the standard is not expected to have a material effect on the timing of the Company's revenue recognition or its financial position, results of operations, net income, or cash flows, but is expected to have an impact on the Company's revenue-related disclosures and internal controls over financial reporting. The Company is not currently able to estimate the impact on the presentation of its future revenues and expenses under the new guidance due to uncertainties with respect to future sales volumes, service costs, locations of producing properties, sales destinations, transportation methods utilized, and changes in the nature, timing, and extent of its arrangements from period to period.

In July 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-11, “Inventory”. This update applies to all inventory that is not measured using last-in, first-out or the retail inventory method. Under this update, an entity should measure inventory at the lower of cost and net realizable value. This standard was effective for financial statements issued for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. This standard should be applied prospectively with early adoption permitted as of the beginning of an interim or annual reporting period. The Company adopted this standard prospectively effective January 1, 2017. The adoption of this standard had no impact on the Company’s financial position, results of operations or liquidity because the Company currently measures its inventory at the lower of cost or net realizable value.

In November 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-17, “Income Taxes”. This update requires that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. The standard was effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. This standard may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. The Company adopted this standard prospectively effective January 1, 2017. The Company will present deferred tax liabilities and assets as noncurrent.

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. While this update will not have a direct impact on the Company, 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 Company 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 Company is still evaluating the impact of this standard.

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. The guidance in this update pertains to the presentation of revenues on a gross basis (revenues presented separately from associated expenses) versus a net basis. Under this guidance, an entity generally shall record revenue on a gross basis if it controls a promised good or service before transferring it to a customer, whereas an entity shall record revenue on a net basis if its role is to arrange for another entity to provide the goods or services to a customer. Significant judgment may be required in some circumstances to determine whether gross or net presentation is appropriate. 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 standard is expected to impact the presentation of future revenues and expenses under the gross-versus-net presentation guidance. The Company plans to adopt the standard on January 1, 2018 using the modified retrospective approach.

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 Company prospectively adopted this standard effective January 1, 2017. The Company revised its calculation of diluted earnings per share to exclude the amount of excess tax benefits that would be recognized in additional paid-in capital. The Company also adopted a policy to account for forfeitures as they occur.

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 Company'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 Company'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 affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company does not believe the adoption of this standard will have a material impact on the Company’s consolidated financial statements since the Company does not have a history of credit losses.

In August 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-15, “Statement of Cash Flows - Classification of Certain Cash Receipts and Cash Payments”. This update apples to all entities that are required to present a statement of cash flows. This update provides guidance on eight specific cash flow issues: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, including bank-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. This update will be effective for financial statements issued for fiscal years beginning after December 31, 2017, including interim periods within those fiscal years with early adoption permitted. This update should be applied using the retrospective transition method. Adoption of this standard will only affect the presentation of the Company’s cash flows and will not have a material impact on the Company’s consolidated financial statements.

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 Company does not expect the adoption of this standard to have a material impact on the Company’s consolidated financial statements.

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 Company’s financial statements or results of operations. The adoption of this update will change the process that the Company uses to evaluate whether the Company has acquired a business or an asset. This update will be applied prospectively and will not have an effect on prior acquisitions.

3. ACQUISITIONS

On February 28, 2017, the Company completed its acquisition of certain oil and natural gas properties, midstream assets and other related assets in the Delaware Basin for an aggregate purchase price consisting of $1.74 billion in cash and 7.69 million shares of the Company’s common stock, of which approximately 1.15 million shares were placed in an indemnity escrow. This transaction includes the acquisition of (i) approximately 100,306 gross (80,339 net) acres primarily in Pecos and Reeves counties for approximately $2.5 billion and (ii) midstream assets for approximately $47.6 million. The Company used the net proceeds from its December 2016 equity offering, net proceeds from its December 2016 debt offering, cash on hand and other financing sources to fund the cash portion of the purchase price for this acquisition.

The following represents the fair value of the assets and liabilities assumed on the acquisition date. The aggregate consideration transferred was $2.5 billion, resulting in no goodwill or bargain purchase gain.

		(in thousands)
Proved oil and natural gas properties	$	386,308
Unevaluated oil and natural gas properties		2,122,597
Midstream assets		47,432
Prepaid capital costs		3,460
Oil inventory		839
Equipment		163
Revenues payable		(9,650)
Asset retirement obligations		(1,550)
Total fair value of net assets	$	2,549,599

The Company has included in its consolidated statements of operations revenues of $84.3 million and direct operating expenses of $16.0 million for the period from February 28, 2017 to September 30, 2017 due to the acquisition.

Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the three and nine months ended September 30, 2017 and 2016 have been prepared to give effect to the February 28, 2017 acquisition as if it had occurred on January 1, 2016. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2016.

The pro forma data also necessarily exclude various operation expenses related to the properties and the financial statements should not be viewed as indicative of operations in future periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands, except per share amounts)			
Revenues	$ 301,253	$ 169,887	$ 828,846	$ 408,303
Income (loss) from operations	142,639	(122,546)	405,699	(265,803)
Net income (loss)	81,948	(131,469)	382,044	(300,739)
Basic earnings per common share	0.74	(1.70)	3.96	(4.10)
Diluted earnings per common share	0.74	(1.70)	3.95	(4.10)

4. 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 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. Viper Energy Partners GP LLC, a fully-consolidated subsidiary of Diamondback, serves as the general partner of, and holds a non-economic general partner interest in, the Partnership. As of September 30, 2017, the Company owned approximately 64% of the common units of the Partnership.

Partnership Agreement

In connection with the closing of the Viper Offering, 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 its 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 months 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 months and nine months ended September 30, 2016, no expenses were allocated to the Partnership by the General Partner.

Tax Sharing

In connection with the closing of the Viper Offering, 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.

Other Agreements

See Note 11—Related Party Transactions for information regarding the advisory services agreement the Partnership and the General Partner entered into with Wexford Capital LP ("Wexford").

The Partnership has entered into a secured revolving credit facility with Wells Fargo, as administrative agent sole book runner and lead arranger. See Note 8—Debt for a description of this credit facility.

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	September 30, 2017	December 31, 2016
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$ 4,672,127	$ 3,429,742
Not subject to depletion	4,197,159	1,730,519
Gross oil and natural gas properties	8,869,286	5,160,261
Accumulated depletion	(906,358)	(687,685)
Accumulated impairment	(1,143,498)	(1,143,498)
Oil and natural gas properties, net	6,819,430	3,329,078
Midstream assets	156,379	8,362
Other property, equipment and land	79,738	58,290
Accumulated depreciation	(6,940)	(4,873)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 7,048,607	$ 3,390,857

Balance of costs not subject to depletion	
Incurred in 2017	$ 2,651,115
Incurred in 2016	779,148
Incurred in 2015	343,381
Incurred in 2014	394,410
Incurred in 2013	29,105
Total not subject to depletion	$ 4,197,159

At September 30, 2017, there was $43.3 million in exploration costs and development costs and $15.4 million in capitalized interest that are not subject to depletion. At December 31, 2016, there were no exploration costs, development costs or capitalized interest that are not subject to depletion.

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. Costs, including related employee costs, associated with production and operation of the properties are charged to expense as incurred. All other internal costs not directly associated with exploration and development activities are charged to expense as they are incurred. Capitalized internal costs were approximately $5.7

million and $3.9 million for the three months ended September 30, 2017 and 2016, respectively, and $15.9 million and $13.0 million for the nine months ended September 30, 2017 and 2016, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years. Acquisition costs not currently being amortized are primarily related to unproved acreage that the Company plans to prove up through drilling. The Company has no plans to let any acreage expire. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

Under this method of accounting, the Company 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 natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash writedown is required.

As a result of the decline in prices, the Company recorded a non-cash impairment for the nine months ended September 30, 2016 of $245.5 million, which is included in accumulated depletion, depreciation, amortization and impairment. The Company did not record an impairment for the nine months ended September 30, 2017. The 2016 impairment charge affected the Company's reported net income but did not reduce its cash flow. In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods.

6. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company's asset retirement obligation liability for the following periods:

	Nine Months Ended September 30,	
	2017	2016
	(in thousands)	
Asset retirement obligations, beginning of period	$ 17,422	$ 12,711
Additional liabilities incurred	1,196	406
Liabilities acquired	2,411	3,022
Liabilities settled	(689)	(402)
Accretion expense	1,030	770
Revisions in estimated liabilities	4	25
Asset retirement obligations, end of period	21,374	16,532
Less current portion	1,392	792
Asset retirement obligations - long-term	$ 19,982	$ 15,740

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance. The current portion of the asset retirement obligation liability is included in other accrued liabilities in the Company's consolidated balance sheets.

7. EQUITY METHOD INVESTMENTS

In October 2014, the Company obtained a 25% interest in HMW Fluid Management LLC, which was formed to develop, own and operate an integrated water management system to gather, store, process, treat, distribute and dispose of water to exploration and production companies operating in Midland, Martin and Andrews Counties, Texas. The board of this entity may also authorize the entity to offer these services to other counties in the Permian Basin and to pursue other business opportunities. During the nine months ended September 30, 2017, the Company invested $0.2 million in this entity and recorded $0.3 million, which is the Company’s share of HMW Fluid Management LLC’s net income, bringing its total investment to $6.8 million at September 30, 2017. During the nine months ended September 30, 2016, the Company invested $0.8 million in this entity and recorded less than $0.1 million, which is the Company’s share of HMW Fluid Management LLC’s net income, bringing its total investment to $4.1 million at September 30, 2016. The Company will retain a minority interest after all commitments are received. The entity was formed as a limited liability company and maintains a specific ownership account for each investor, similar to a partnership capital account structure. Therefore, the Company accounts for this investment under the equity method of accounting.

8. DEBT

Long-term debt consisted of the following as of the dates indicated:

	September 30, 2017	December 31, 2016
	(in thousands)	
4.750 % Senior Notes due 2024	$ 500,000	$ 500,000
5.375 % Senior Notes due 2025	500,000	500,000
Unamortized debt issuance costs	(13,612)	(14,588)
Revolving credit facility	234,500	—
Partnership revolving credit facility	35,500	120,500
Total long-term debt	$ 1,256,388	$ 1,105,912

2024 Senior Notes

On October 28, 2016, the Company issued $500.0 million in aggregate principal amount of 4.750% Senior Notes due 2024 (the “2024 Senior Notes”). The 2024 Senior Notes bear interest at a rate of 4.750% per annum, payable semi-annually, in arrears on May 1 and November 1 of each year, commencing on May 1, 2017 and will mature on November 1, 2024. All of the Company’s existing and future restricted subsidiaries that guarantee its revolving credit facility or certain other debt guarantee the 2024 Senior Notes; provided, however, that the 2024 Senior Notes are not guaranteed by the Partnership, the General Partner, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of the Company’s future unrestricted subsidiaries.

The 2024 Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented (the “2024 Indenture”). The 2024 Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company’s ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting the Company’s restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of the Company’s subsidiaries as unrestricted subsidiaries.

The Company may on any one or more occasions redeem some or all of the 2024 Senior Notes at any time on or after November 1, 2019 at the redemption prices (expressed as percentages of principal amount) of 103.563% for the 12-month period beginning on November 1, 2019, 102.375% for the 12-month period beginning on November 1, 2020, 101.188% for the 12-month period beginning on November 1, 2021 and 100.000% beginning on November 1, 2022 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to November 1, 2019, the Company may on any one or more occasions redeem all or a portion of the 2024 Senior Notes at a price equal to 100% of the principal amount of the 2024 Senior Notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to November 1, 2019, the Company may on any one or more occasions redeem the 2024 Senior Notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2024 Senior Notes issued prior to such date at a redemption price of 104.750%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

2025 Senior Notes

On December 20, 2016, the Company issued $500.0 million in aggregate principal amount of 5.375% Senior Notes due 2025 (the “2025 Senior Notes”). The 2025 Senior Notes bear interest at a rate of 5.375% per annum, payable semi-annually, in arrears on May 31 and November 30 of each year, commencing on May 31, 2017 and will mature on May 31, 2025. All of the Company’s existing and future restricted subsidiaries that guarantee its revolving credit facility or certain other debt guarantee the 2025 Senior Notes, provided, however, that the 2025 Senior Notes are not guaranteed by the Partnership, the General Partner, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of the Company’s future unrestricted subsidiaries.

The 2025 Senior Notes were issued under an indenture, dated as of December 20, 2016, among the Company, the guarantors party thereto and Wells Fargo Bank, as the trustee (the “2025 Indenture”). The 2025 Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company’s ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting the Company’s restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of the Company’s subsidiaries as unrestricted subsidiaries.

The Company may on any one or more occasions redeem some or all of the 2025 Senior Notes at any time on or after May 31, 2020 at the redemption prices (expressed as percentages of principal amount) of 104.031% for the 12-month period beginning on May 31, 2020, 102.688% for the 12-month period beginning on May 31, 2021, 101.344% for the 12-month period beginning on May 31, 2022 and 100.000% beginning on May 31, 2023 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to May 31, 2020, the Company may on any one or more occasions redeem all or a portion of the 2025 Senior Notes at a price equal to 100% of the principal amount of the 2025 Senior Notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to May 31, 2020, the Company may on any one or more occasions redeem the 2025 Senior Notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2025 Senior Notes issued prior to such date at a redemption price of 105.375%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

As required under the terms of the registration rights agreements relating to the 2024 Senior Notes and the 2025 Senior Notes, on April 26, 2017, the Company filed with the SEC a Registration Statement on Form S-4 (the “Registration Statement”) relating to the exchange offers of the 2024 Senior Notes and the 2025 Senior Notes for substantially identical notes registered under the Securities Act (the “Exchange Offers”). The Registration Statement was declared effective by the SEC on June 21, 2017 and the Exchange Offers closed on July 27, 2017, in which all of the privately placed 2024 Senior Notes and 2025 Senior Notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act.

The Company’s Credit Facility

On June 9, 2014, Diamondback O&G LLC, as borrower, entered into a first amendment and on November 13, 2014, Diamondback O&G LLC entered into a second amendment to the second amended and restated credit agreement, dated November 1, 2013 (the “credit agreement”). The first amendment modified certain provisions of the credit agreement to, among other things, allow one or more of the Company’s subsidiaries to be designated as “Unrestricted Subsidiaries” that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, the Partnership, the General Partner and Viper Energy Partners LLC were designated as unrestricted subsidiaries under the credit agreement. As of September 30, 2017, the credit agreement was guaranteed by Diamondback, Diamondback E&P LLC and Rattler Midstream LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of the assets of Diamondback O&G LLC, the Company and the other guarantors.

The second amendment increased the maximum amount of the credit facility to $2.0 billion, modified the dates and deadlines of the credit agreement relating to the scheduled borrowing base redeterminations based on the Company's oil and natural gas reserves and other factors and added new provisions that allow the Company to elect a commitment amount that is less than its borrowing base as determined by the lenders. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Company 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 $1.5 billion, of which the Company had elected a commitment amount of $750.0 million, and the Company had $234.5 million in outstanding borrowings.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company 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 0.50% 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 Company 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), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2018.

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

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

The covenant prohibiting additional indebtedness, as amended in December 2016, allows for the issuance of unsecured debt of up to $1.0 billion in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of September 30, 2017, the Company had $1.0 billion in aggregate principal amount of senior unsecured notes outstanding.

As of September 30, 2017 and December 31, 2016, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the Company's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

The Partnership's Credit Agreement

The Partnership entered into 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 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 the 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 0.5% 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 subsidiaries.

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.

9. CAPITAL STOCK AND EARNINGS PER SHARE

In January 2016, the Company completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $55.33 per share and the Company received proceeds of approximately $254.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In July 2016, the Company completed an underwritten public offering of 6,325,000 shares of common stock, which included 825,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriter. The stock was sold to the underwriter at $87.24 per share and the Company received proceeds of approximately $551.8 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions, which together with cash on hand were used to fund the acquisition of certain leasehold interests and related assets in the Southern Delaware Basin.

Diamondback completed no equity offerings during the nine months ended September 30, 2017.

Partnership Equity Offerings

In January 2017, the Partnership 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. The Partnership received net proceeds from this offering of approximately $147.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which the Partnership used $120.5 million to repay the outstanding borrowings under its revolving credit agreement and the balance was used for general partnership purposes, which included additional acquisitions.

In July 2017, the Partnership 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. In this offering, the Company purchased 700,000 common units, an affiliate of the General Partner purchased 3,000,000 common units and certain officers and directors of the Company and the General Partner purchased an aggregate of 114,000 common units, in each case directly from the underwriters. Following this offering, the Company had an approximate 64% limited partner interest in the Partnership. The Partnership received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which the Partnership used $152.8 million to repay all of the then-outstanding borrowings under the Partnership's revolving credit facility and the balance was used to fund a portion of the purchase price for acquisitions and for general partnership purposes.

Earnings Per Share

The Company's basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted earnings per share include the effect of potentially dilutive shares outstanding for the period. Additionally, for the diluted earnings per share computation, the per share earnings of the Partnership are included in the consolidated earnings per share computation based on the consolidated group's holdings of the subsidiary.

A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
	(in thousands, except per share amounts)			
Net income (loss) attributable to common stock	$ 73,024	$ (2,230)	$ 367,702	$ (190,632)
Weighted average common shares outstanding				
Basic weighted average common units outstanding	98,144	77,167	96,491	73,318
Effect of dilutive securities:				
Potential common shares issuable	225	—	261	—
Diluted weighted average common shares outstanding	98,369	77,167	96,752	73,318
Basic net income (loss) attributable to common stock	$ 0.74	$ (0.03)	$ 3.81	$ (2.60)
Diluted net income (loss) attributable to common stock	$ 0.74	$ (0.03)	$ 3.80	$ (2.60)

For the three months ended September 30, 2017 and 2016, there were 52,857 shares and 192,155 shares, respectively, and during the nine months ended September 30, 2017 and 2016, there were 1,248 shares and 288,739 shares, respectively, that were not included in the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented. These shares could dilute basic earnings per share in future periods.

10. EQUITY-BASED COMPENSATION

The following table presents the effects of the equity compensation plans and related costs:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
General and administrative expenses	$ 6,187	$ 6,265	$ 19,418	$ 20,643
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	2,167	916	6,411	5,525

Stock Options

The following table presents the Company's stock option activity under the Company's Equity Incentive Plan ("Equity Plan") for the nine months ended September 30, 2017.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term	Intrinsic Value
			(in years)	(in thousands)
Outstanding at December 31, 2016	15,750	$ 22.72		
Exercised	(15,750)	$ 22.72		
Outstanding at September 30, 2017	—	$ —	0.00	$ —

The aggregate intrinsic value of stock options that were exercised during the nine months ended September 30, 2017 and 2016 was $1.2 million and $1.3 million, respectively.

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the Equity Plan during the nine months ended September 30, 2017.

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2016	206,004	$ 70.33
Granted	97,361	$ 106.15
Vested	(147,934)	$ 77.44
Forfeited	(2,600)	$ 87.95
Unvested at September 30, 2017	152,831	$ 85.96

The aggregate fair value of restricted stock units that vested during the nine months ended September 30, 2017 and 2016 was $14.8 million and $11.8 million, respectively. As of September 30, 2017, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $8.4 million. Such cost is expected to be recognized over a weighted-average period of 1.3 years.

Performance Based Restricted Stock Units

To provide long-term incentives for the executive officers to deliver competitive returns to the Company's stockholders, the Company has granted performance-based restricted stock units to eligible employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total stockholder return of the Company's common stock ("TSR") as compared to a designated peer group during a two-year or three-year performance period.

In February 2017, eligible employees received performance restricted stock unit awards totaling 37,440 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2017 to December 31, 2018 and cliff vest at December 31, 2018. Eligible employees received additional performance restricted stock unit awards totaling 74,880 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2017 to December 31, 2019 and cliff vest at December 31, 2019.

The fair value of each performance restricted stock unit is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period.

The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions for the February 2017 awards.

	2017	
	Two-Year Performance Period	Three-Year Performance Period
Grant-date fair value	$ 162.13	$ 168.73
Risk-free rate	1.27%	1.59%
Company volatility	39.32%	41.14%

The following table presents the Company’s performance restricted stock units activity under the Equity Plan for the nine months ended September 30, 2017.

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2016	252,471	$ 103.06
Granted	118,169	$ 166.53
Unvested at September 30, 2017[(1)]	370,640	$ 123.29

(1) A maximum of 741,280 units could be awarded based upon the Company’s final TSR ranking.

As of September 30, 2017, the Company’s unrecognized compensation cost related to unvested performance based restricted stock awards and units was $20.6 million. Such cost is expected to be recognized over a weighted-average period of 1.6 years.

Phantom Units

Under the Viper 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 one common unit of the Partnership for each phantom unit.

The following table presents the phantom unit activity under the Viper 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.

11. RELATED PARTY TRANSACTIONS

Immediately upon the completion of the Company's initial public offering on October 17, 2012, Wexford beneficially owned approximately 44% of the Company's outstanding common stock. As of December 31, 2016, Wexford beneficially owned less than 1% of the Company's outstanding common stock. The Chairman of the Board of Directors of both the Company and the General Partner was a partner at Wexford until his retirement from Wexford effective December 31, 2016. Another partner at Wexford serves as a member of the Board of Directors of the General Partner. Beginning January 1, 2017, Wexford and entities affiliated with Wexford are no longer considered related parties of the Company and any expenses after December 31, 2016 are no longer classified as related party expenses.

Related Party Revenue and Expenses

During the three months ended September 30, 2016, the Company paid $0.8 million in lease operating expenses and $0.6 million in general and administrative expenses to related parties. During the three months ended September 30, 2016, the Company received less than $0.1 million in other income from related parties. During the nine months ended September 30, 2016, the Company paid $2.4 million in lease operating expenses and $1.6 million in general and administrative expenses to related parties. During the nine months ended September 30, 2016, the Company received $0.1 million in other income from related parties.

Advisory Services Agreement - The Company

The Company entered into an advisory services agreement (the "Advisory Services Agreement") with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement had an initial term of two years commencing on October 18, 2012, and continues for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. The Company incurred total costs of $0.1 million and $0.4 million during the three months and nine months ended September 30, 2016, respectively, under the Advisory Services Agreement.

Advisory Services Agreement - The Partnership

In connection with the closing of the Viper Offering, the Partnership and the General Partner entered into an advisory services agreement (the "Viper Advisory Services Agreement") with Wexford, dated as of June 23, 2014, under which Wexford provides the Partnership and the General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Viper Advisory Services Agreement had an initial term of two years commencing on June 23, 2014, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. The Partnership did not incur any costs during the three months and nine months ended September 30, 2017 or September 30, 2016 under the Viper Advisory Services Agreement.

Midland Corporate Lease

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with an initial five-year term, which was extended for an additional ten-years in November 2014. The office space is owned by Fasken, which is controlled by an affiliate of Wexford. The Company paid rent of $0.4 million and $1.1 million for the three months and nine months ended September 30, 2016, respectively.

Field Office Lease

The Company leased field office space in Midland, Texas from an unrelated third party commencing on March 1, 2011. On March 1, 2014, the building was purchased by WT Commercial Portfolio, LLC, which is controlled by an affiliate of Wexford. The term of the lease expires on February 28, 2018. During the third quarter of 2014, the Company entered into a sublease with Bison, in which Bison leased the field office space on the same terms as the Company's lease for the remainder of the lease term. The Company paid rent of less than $0.1 million and $0.1 million during the three months and nine months ended September 30, 2016, respectively. The Company received payments of less than $0.1 million and $0.1 million from Bison in respect of this sublease during the three months and nine months ended September 30, 2016, respectively. During the second quarter of 2017, the sublease between the Company and Bison as well as the original lease between the Company and WT Commercial Portfolio, LLC were terminated.

The Partnership - Lease Bonus

During the three months ended September 30, 2017, the Company did not pay the Partnership any lease bonus extension payments. During the nine months ended September 30, 2017, the Company 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, the Company 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, the Company 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.

12. INCOME TAXES

The Company’s effective income tax rates were 1.2% and (0.2)% for the nine months ended September 30, 2017 and 2016, respectively. Total income tax expense for the nine months ended September 30, 2017 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income primarily due to current and deferred state income taxes and the change in valuation allowance that offsets the Company’s federal net deferred tax asset position. The Company incurs state income tax obligations in Texas, the primary state in which it operates, pursuant to the Texas margin tax. Any positive net taxable income generated by the Company for federal income tax purposes for the nine months ended September 30, 2017 is expected to be offset by federal net operating loss (“NOL”) carryforwards, for which a full valuation allowance has been provided. During the nine months ended September 30, 2017, the Company reduced its valuation allowance against its federal NOL by $111.7 million, bringing the total valuation allowance to $2.7 million. The valuation allowance reduces the Company’s federal deferred tax assets to a zero value, as management does not believe that it is more-likely-than-not that this portion of the Company's NOLs are realizable. Management believes that the balance of the Company's NOLs are realizable only to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

13. DERIVATIVES

All derivative financial instruments are recorded at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the combined consolidated statements of operations under the caption “Gain (loss) on derivative instruments, net.”

The Company has used fixed price swap contracts, fixed price basis swap contracts and costless collars with corresponding put and call options to reduce price volatility associated with certain of its oil and natural gas sales. With respect to the Company’s fixed price swap contracts and fixed price basis swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap or basis price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap or basis price. The Company has fixed price basis swaps for the spread between the WTI Midland price and the WTI Cushing price. Under the Company’s costless collar contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the put option price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the call option price. If the settlement price is between the put and the call price, there is no payment required. The Company’s derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing and Crude Oil Brent, and with natural gas derivative settlements based on the New York Mercantile Exchange Henry Hub pricing.

By using derivative instruments to hedge exposure to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company’s counterparties are participants in the secured second amended and restated credit agreement, which is secured by substantially all of the assets of the guarantor subsidiaries; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company has entered into derivative instruments only with counterparties that are also lenders in our credit facility and have been deemed an acceptable credit risk.

As of September 30, 2017, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	2017		2018		2019	
	Volume (Bbls/MMBtu)	**Fixed Price Swap (per Bbl/MMBtu)**	**Volume (Bbls/MMBtu)**	**Fixed Price Swap (per Bbl/MMBtu)**	**Volume (Bbls/MMBtu)**	**Fixed Price Swap (per Bbl/MMBtu)**
Oil Swaps - WTI	1,288,000	$ 53.37	8,204,000	$ 50.61	1,095,000	$ 49.82
Oil Swaps - BRENT	—	$ —	1,555,000	$ 54.68	—	$ —
Oil Basis Swaps	2,208,000	$ (0.72)	5,475,000	$ (0.88)	—	$ —
Natural Gas Swaps	2,760,000	$ 3.26	5,000,000	$ 3.21	—	$ —

	Floor		Ceiling	
	Volume (Bbls)	**Fixed Price (per Bbl)**	**Volume (Bbls)**	**Fixed Price (per Bbl)**
October 2017 - December 2017				
Costless Collars	1,656,000	$ 47.11	828,000	$ 56.05
January 2018 - March 2018				
Costless Collars	540,000	$ 47.00	270,000	$ 56.34

Balance sheet offsetting of derivative assets and liabilities

The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions that are with the same counterparty and are subject to contractual terms which provide for net settlement.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company’s consolidated balance sheets as of September 30, 2017 and December 31, 2016.

	September 30, 2017	December 31, 2016
	(in thousands)	
Gross amounts of assets presented in the Consolidated Balance Sheet	$ 1,614	$ 709
Net amounts of assets presented in the Consolidated Balance Sheet	1,614	709
Gross amounts of liabilities presented in the Consolidated Balance Sheet	14,148	22,608
Net amounts of liabilities presented in the Consolidated Balance Sheet	$ 14,148	$ 22,608

The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The net fair value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	September 30, 2017	December 31, 2016
	(in thousands)	
Current assets: derivative instruments	$ 1,614	$ —
Noncurrent assets: derivative instruments	—	709
Total assets	$ 1,614	$ 709
Current liabilities: derivative instruments	$ 10,003	$ 22,608
Noncurrent liabilities: derivative instruments	4,145	—
Total liabilities	$ 14,148	$ 22,608

None of the Company's derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following table summarizes the gains and losses on derivative instruments included in the consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands)			
Change in fair value of open non-hedge derivative instruments	$ (58,645)	$ 2,425	$ 9,365	$ (12,858)
Gain (loss) on settlement of non-hedge derivative instruments	8,000	(391)	11,011	4,193
Gain (loss) on derivative instruments	$ (50,645)	$ 2,034	$ 20,376	$ (8,665)

14. FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company's derivative instruments. The fair values of the Company's fixed price swaps, fixed price basis swaps and costless collars are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2017 and December 31, 2016.

	September 30, 2017	December 31, 2016
	(in thousands)	
Fixed price swaps:		
Quoted prices in active markets level 1	$ —	$ —
Significant other observable inputs level 2	(12,534)	23,317
Significant unobservable inputs level 3	—	—
Total	$ (12,534)	$ 23,317

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated balance sheets.

	September 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$ 234,500	$ 234,500	$ —	$ —
4.750% Senior Notes due 2024	500,000	511,875	500,000	491,250
5.375% Senior Notes due 2025	500,000	523,750	500,000	502,850
Partnership revolving credit facility	35,500	35,500	120,500	120,500

The fair value of the revolving credit facility and the Partnership's revolving credit facility approximates their carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the September 30, 2017 quoted market price, a Level 1 classification in the fair value hierarchy.

15. COMMITMENTS AND CONTINGENCIES

The Company 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.

16. SUBSEQUENT EVENTS

Commodity Contracts

Subsequent to September 30, 2017, the Company entered into new fixed price swaps. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing and Crude Oil Brent.

The following tables present the derivative contracts entered into by the Company subsequent to September 30, 2017. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
January 2018 - December 2018		
Oil Swaps - WTI	1,098,000	$ 52.82
Oil Swaps - BRENT	275,000	$ 56.10

The Company's Credit Facility

In connection with the Company's fall 2017 redetermination which is expected to be completed in November 2017, the lead lender has proposed an increase in the Company's borrowing base under its facility from $1.5 billion to $1.8 billion, and the Company intends to increase its elected commitment amount from $750.0 million to $1.0 billion. The proposed increase in the Company's borrowing base is subject to approval of the additional lenders within the syndicate.

The Partnership's Credit Facility

In connection with the Partnership's fall 2017 redetermination which is expected to be completed in November 2017, the lead lender has proposed an increase in the Partnership's borrowing base under its facility from $315.0 million to $400.0 million. The proposed increase in the Partnership’s borrowing base is subject to approval of the additional lenders within the syndicate.

17. GUARANTOR FINANCIAL STATEMENTS

As of September 30, 2017, Diamondback E&P LLC and Diamondback O&G LLC (the “Guarantor Subsidiaries”) are guarantors under the indentures relating to the 2024 Senior Notes and the 2025 Senior Notes. In connection with the issuance of the 2024 Senior Notes and the 2025 Senior Notes, the Partnership, the General Partner, Viper Energy Partners LLC and Rattler Midstream LLC were designated as Non-Guarantor Subsidiaries. The following presents condensed consolidated financial information for the Company (which for purposes of this Note 17 is referred to as the “Parent”), the Guarantor Subsidiaries and the Non–Guarantor Subsidiaries on a consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC’s Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

Condensed Consolidated Balance Sheet
September 30, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 20,856	$ 4,911	$ 4,438	$ —	$ 30,205
Accounts receivable	—	136,479	17,199	—	153,678
Accounts receivable - related party	—	14	3,646	(3,646)	14
Intercompany receivable	2,521,304	1,268,866	—	(3,790,170)	—
Inventories	—	4,834	—	—	4,834
Other current assets	204	4,772	147	—	5,123
Total current assets	2,542,364	1,419,876	25,430	(3,793,816)	193,854
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	7,804,308	1,065,392	(414)	8,869,286
Midstream assets	—	156,379	—	—	156,379
Other property, equipment and land	—	79,738	—	—	79,738
Accumulated depletion, depreciation, amortization and impairment	—	(1,885,509)	(177,534)	6,247	(2,056,796)
Net property and equipment	—	6,154,916	887,858	5,833	7,048,607
Derivative instruments	—	—	—	—	—
Investment in subsidiaries	3,365,868	—	—	(3,365,868)	—
Other assets	—	10,178	34,929	—	45,107
Total assets	$ 5,908,232	$ 7,584,970	$ 948,217	$ (7,153,851)	$ 7,287,568
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 74,590	$ 110	$ —	$ 74,700
Intercompany payable	—	3,793,816	—	(3,793,816)	—
Other current liabilities	20,031	320,139	2,747	—	342,917
Total current liabilities	20,031	4,188,545	2,857	(3,793,816)	417,617
Long-term debt	986,388	234,500	35,500	—	1,256,388
Derivative instruments	—	4,145	—	—	4,145
Asset retirement obligations	—	19,982	—	—	19,982
Deferred income taxes	3,313	—	—	—	3,313
Total liabilities	1,009,732	4,447,172	38,357	(3,793,816)	1,701,445
Commitments and contingencies					
Stockholders' equity	4,898,500	3,137,798	909,860	(4,047,658)	4,898,500
Non-controlling interest	—	—	—	687,623	687,623
Total equity	4,898,500	3,137,798	909,860	(3,360,035)	5,586,123
Total liabilities and equity	$ 5,908,232	$ 7,584,970	$ 948,217	$ (7,153,851)	$ 7,287,568

Condensed Consolidated Balance Sheet
December 31, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 1,643,226	$ 14,135	$ 9,213	$ —	$ 1,666,574
Restricted cash	—	—	500	—	500
Accounts receivable	—	109,782	10,043	—	119,825
Accounts receivable - related party	—	297	3,470	(3,470)	297
Intercompany receivable	3,060,566	359,502	—	(3,420,068)	—
Inventories	—	1,983	—	—	1,983
Other current assets	481	2,319	187	—	2,987
Total current assets	4,704,273	488,018	23,413	(3,423,538)	1,792,166
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	4,400,002	760,818	(559)	5,160,261
Midstream assets	—	8,362	—	—	8,362
Other property, equipment and land	—	58,290	—	—	58,290
Accumulated depletion, depreciation, amortization and impairment	—	(1,695,701)	(148,948)	8,593	(1,836,056)
Net property and equipment	—	2,770,953	611,870	8,034	3,390,857
Funds held in escrow	—	121,391	—	—	121,391
Derivative instruments	—	709	—	—	709
Investment in subsidiaries	(15,500)	—	—	15,500	—
Other assets	—	9,291	35,266	—	44,557
Total assets	$ 4,688,773	$ 3,390,362	$ 670,549	$ (3,400,004)	$ 5,349,680
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$ 30	$ 45,838	$ 1,780	$ —	$ 47,648
Accounts payable-related party	1	—	—	—	1
Intercompany payable	—	3,423,538	—	(3,423,538)	—
Other current liabilities	5,868	155,454	371	—	161,693
Total current liabilities	5,899	3,624,830	2,151	(3,423,538)	209,342
Long-term debt	985,412	—	120,500	—	1,105,912
Asset retirement obligations	—	16,134	—	—	16,134
Total liabilities	991,311	3,640,964	122,651	(3,423,538)	1,331,388
Commitments and contingencies					
Stockholders’ equity	3,697,462	(250,602)	547,898	(297,296)	3,697,462
Non-controlling interest	—	—	—	320,830	320,830
Total equity	3,697,462	(250,602)	547,898	23,534	4,018,292
Total liabilities and equity	$ 4,688,773	$ 3,390,362	$ 670,549	$ (3,400,004)	$ 5,349,680

Condensed Consolidated Statement of Operations
Three Months Ended September 30, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 223,038	$ —	$ 36,011	$ 259,049
Natural gas sales	—	11,774	—	3,148	14,922
Natural gas liquid sales	—	22,214	—	3,052	25,266
Royalty income	—	—	42,211	(42,211)	—
Lease bonus income	—	—	322	—	322
Midstream services	—	1,694	—	—	1,694
Total revenues	—	258,720	42,533	—	301,253
Costs and expenses:					
Lease operating expenses	—	32,498	—	—	32,498
Production and ad valorem taxes	—	15,546	2,825	—	18,371
Gathering and transportation	—	3,271	205	—	3,476
Midstream services	—	4,445	—	—	4,445
Depreciation, depletion and amortization	—	74,766	11,068	1,745	87,579
General and administrative expenses	6,506	4,629	1,368	(615)	11,888
Asset retirement obligation accretion	—	357	—	—	357
Total costs and expenses	6,506	135,512	15,466	1,130	158,614
Income (loss) from operations	(6,506)	123,208	27,067	(1,130)	142,639
Other income (expense)					
Interest expense	(6,393)	(1,940)	(859)	—	(9,192)
Other income	9	210	399	(615)	3
Loss on derivative instruments, net	—	(50,645)	—	—	(50,645)
Total other income (expense), net	(6,384)	(52,375)	(460)	(615)	(59,834)
Income (loss) before income taxes	(12,890)	70,833	26,607	(1,745)	82,805
Provision for income taxes	857	—	—	—	857
Net income (loss)	(13,747)	70,833	26,607	(1,745)	81,948
Net income attributable to non-controlling interest	—	—	—	8,924	8,924
Net income (loss) attributable to Diamondback Energy, Inc.	$ (13,747)	$ 70,833	$ 26,607	$ (10,669)	$ 73,024

Condensed Consolidated Statement of Operations
Three Months Ended September 30, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 108,273	$ —	$ 18,080	$ 126,353
Natural gas sales	—	5,581	—	753	6,334
Natural gas liquid sales	—	8,285	—	1,159	9,444
Royalty income	—	—	19,992	(19,992)	—
Lease bonus income	—	—	5	(5)	—
Total revenues	—	122,139	19,997	(5)	142,131
Costs and expenses:					
Lease operating expenses	—	22,180	—	—	22,180
Production and ad valorem taxes	—	7,694	1,429	—	9,123
Gathering and transportation	—	2,773	70	—	2,843
Depreciation, depletion and amortization	—	38,572	6,751	(577)	44,746
Impairment of oil and natural gas properties	—	46,368	—	—	46,368
General and administrative expenses	5,736	3,019	1,153	—	9,908
Asset retirement obligation accretion	—	270	—	—	270
Total costs and expenses	5,736	120,876	9,403	(577)	135,438
Income (loss) from operations	(5,736)	1,263	10,594	572	6,693
Other income (expense)					
Interest expense	(8,847)	(729)	(658)	—	(10,234)
Other income	199	442	266	—	907
Gain on derivative instruments, net	—	2,034	—	—	2,034
Total other expense, net	(8,648)	1,747	(392)	—	(7,293)
Net income (loss)	(14,384)	3,010	10,202	572	(600)
Net income attributable to non-controlling interest	—	—	—	1,630	1,630
Net income (loss) attributable to Diamondback Energy, Inc.	$ (14,384)	$ 3,010	$ 10,202	$ (1,058)	$ (2,230)

Condensed Consolidated Statement of Operations
Nine Months Ended September 30, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 607,381	$ —	$ 96,626	$ 704,007
Natural gas sales	—	31,088	—	6,449	37,537
Natural gas liquid sales	—	50,506	—	7,119	57,625
Royalty income	—	—	110,194	(110,194)	—
Lease bonus income	—	—	2,613	(106)	2,507
Midstream services	—	4,241	—	—	4,241
Total revenues	—	693,216	112,807	(106)	805,917
Costs and expenses:					
Lease operating expenses	—	88,113	—	—	88,113
Production and ad valorem taxes	—	42,307	7,668	—	49,975
Gathering and transportation	—	8,618	492	—	9,110
Midstream services	—	7,127	—	—	7,127
Depreciation, depletion and amortization	—	190,748	28,587	2,346	221,681
General and administrative expenses	20,046	14,259	5,064	(1,845)	37,524
Asset retirement obligation accretion	—	1,030	—	—	1,030
Total costs and expenses	20,046	352,202	41,811	501	414,560
Income (loss) from operations	(20,046)	341,014	70,996	(607)	391,357
Other income (expense)					
Interest expense	(23,526)	(4,022)	(2,114)	—	(29,662)
Other income	1,101	9,690	526	(1,845)	9,472
Gain on derivative instruments, net	—	20,376	—	—	20,376
Total other income (expense), net	(22,425)	26,044	(1,588)	(1,845)	186
Income (loss) before income taxes	(42,471)	367,058	69,408	(2,452)	391,543
Provision for income taxes	4,393	—	—	—	4,393
Net income (loss)	(46,864)	367,058	69,408	(2,452)	387,150
Net income attributable to non-controlling interest	—	—	—	19,448	19,448
Net income (loss) attributable to Diamondback Energy, Inc.	$ (46,864)	$ 367,058	$ 69,408	$ (21,900)	$ 367,702

Condensed Consolidated Statement of Operations
Nine Months Ended September 30, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 260,180	$ —	$ 46,518	$ 306,698
Natural gas sales	—	12,561	—	1,904	14,465
Natural gas liquid sales	—	18,440	—	2,492	20,932
Royalty income	—	—	50,914	(50,914)	—
Lease bonus income	—	—	309	(309)	—
Total revenues	—	291,181	51,223	(309)	342,095
Costs and expenses:					
Lease operating expenses	—	59,080	—	—	59,080
Production and ad valorem taxes	—	21,110	4,134	—	25,244
Gathering and transportation	—	7,815	247	2	8,064
Depreciation, depletion and amortization	—	107,807	21,485	(2,606)	126,686
Impairment of oil and natural gas properties	—	198,067	47,469	—	245,536
General and administrative expenses	20,110	8,192	4,109	—	32,411
Asset retirement obligation accretion	—	770	—	—	770
Total costs and expenses	20,110	402,841	77,444	(2,604)	497,791
Income (loss) from operations	(20,110)	(111,660)	(26,221)	2,295	(155,696)
Other income (expense)					
Interest expense	(26,549)	(2,173)	(1,544)	—	(30,266)
Other income	319	966	612	(250)	1,647
Loss on derivative instruments, net	—	(8,665)	—	—	(8,665)
Total other expense, net	(26,230)	(9,872)	(932)	(250)	(37,284)
Income (loss) before income taxes	(46,340)	(121,532)	(27,153)	2,045	(192,980)
Provision for income taxes	368	—	—	—	368
Net income (loss)	(46,708)	(121,532)	(27,153)	2,045	(193,348)
Net loss attributable to non-controlling interest	—	—	—	(2,716)	(2,716)
Net income (loss) attributable to Diamondback Energy, Inc.	$ (46,708)	$ (121,532)	$ (27,153)	$ 4,761	$ (190,632)

Condensed Consolidated Statement of Cash Flows
Nine Months Ended September 30, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (25,369)	$ 569,330	$ 94,057	$ —	$ 638,018
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(531,489)	—	—	(531,489)
Additions to midstream assets	—	(22,491)	—	—	(22,491)
Purchase of other property and equipment	—	(21,534)	—	—	(21,534)
Acquisition of leasehold interests	—	(1,892,864)	—	—	(1,892,864)
Acquisition of mineral interests	—	(69,722)	(301,133)	—	(370,855)
Acquisition of midstream assets	—	(50,279)	—	—	(50,279)
Proceeds from sale of assets	—	3,584	—	—	3,584
Funds held in escrow	—	121,391	—	—	121,391
Equity investments	—	(188)	—	—	(188)
Intercompany transfers	(1,651,328)	1,651,328	—	—	—
Net cash used in investing activities	(1,651,328)	(812,264)	(301,133)	—	(2,764,725)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	312,500	220,500	—	533,000
Repayment on credit facility	—	(78,000)	(305,500)	—	(383,500)
Purchase of subsidiary units by parent	(10,068)	—	—	10,068	—
Debt issuance costs	(744)	(790)	(180)	—	(1,714)
Public offering costs	(77)	—	(433)	—	(510)
Proceeds from public offerings	—	—	380,412	(10,068)	370,344
Distribution from subsidiary	64,858	—	—	(64,858)	—
Exercise of stock options	358	—	—	—	358
Distribution to non-controlling interest	—	—	(92,498)	64,858	(27,640)
Net cash provided by financing activities	54,327	233,710	202,301	—	490,338
Net decrease in cash and cash equivalents	(1,622,370)	(9,224)	(4,775)	—	(1,636,369)
Cash and cash equivalents at beginning of period	1,643,226	14,135	9,213	—	1,666,574
Cash and cash equivalents at end of period	$ 20,856	$ 4,911	$ 4,438	$ —	$ 30,205

Condensed Consolidated Statement of Cash Flows
Nine Months Ended September 30, 2016
(In thousands)

	Parent	Guarantor Subsidiaries	Non– Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (19,148)	$ 198,944	$ 46,550	$ —	$ 226,346
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(242,246)	—	—	(242,246)
Purchase of other property and equipment	—	(9,805)	—	—	(9,805)
Acquisition of leasehold interests	—	(591,785)	—	—	(591,785)
Acquisition of mineral interests	—	—	(137,782)	—	(137,782)
Additions to midstream assets	—	(1,188)	—	—	(1,188)
Proceeds from sale of assets	—	1,566	—	—	1,566
Equity investments	—	(800)	—	—	(800)
Intercompany transfers	(652,211)	652,211	—	—	—
Net cash used in investing activities	(652,211)	(192,047)	(137,782)	—	(982,040)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	—	98,000	—	98,000
Repayment on credit facility	—	(11,000)	(78,000)	—	(89,000)
Debt issuance costs	—	(93)	(35)	—	(128)
Public offering costs	(356)	—	(444)	—	(800)
Proceeds from public offerings	775,095	—	125,580	—	900,675
Distribution from subsidiary	40,253	—	—	(40,253)	—
Exercise of stock options	498	—	—	—	498
Distribution to non-controlling interest	—	—	(46,650)	40,253	(6,397)
Intercompany transfers	(11,000)	11,000	—	—	—
Net cash provided by (used in) financing activities	804,490	(93)	98,451	—	902,848
Net increase in cash and cash equivalents	133,131	6,804	7,219	—	147,154
Cash and cash equivalents at beginning of period	148	19,428	539	—	20,115
Cash and cash equivalents at end of period	$ 133,279	$ 26,232	$ 7,758	$ —	$ 167,269

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 consolidated 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 an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Our activities are primarily directed at the horizontal development of the Wolfcamp and Spraberry formations in the Midland Basin and the Wolfcamp and Bone Spring formations in the Delaware Basin. We intend to continue to develop our reserves and increase production through development drilling and exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production.

The following table sets forth our production data for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Oil (Bbls)	73%	73%	74%	73%
Natural gas (Mcf)	13%	11%	12%	11%
Natural gas liquids (Bbls)	14%	16%	14%	16%
	100%	100%	100%	100%

As of September 30, 2017, we had approximately 190,887 net acres, which consisted of approximately 86,159 net acres in the Northern Midland Basin and approximately 104,728 net acres in the Southern Delaware Basin. We have an estimated 4,300 gross horizontal locations economic at $50 per Bbl West Texas Intermediate.

The challenging commodity price environment that we experienced in 2016 has continued in 2017. Although oil prices have improved, the commodity market continued to be volatile during the third quarter of 2017. We believe we remain well-positioned in this environment. In 2017, we have again demonstrated our operational focus on achieving best-in-class execution, low-cost operations and a conservative balance sheet as we continue to reduce drilling days, well costs and operating expenses while maintaining what we believe to be a peer leading leverage ratio. We are currently operating nine rigs and four completion crews and plan to operate between nine and ten rigs for the remainder of 2017 at current commodity prices.

2017 Highlights

Our Recent Acquisition

On February 28, 2017, we completed our acquisition of oil and natural gas properties, midstream assets and other related assets in the Delaware Basin for an aggregate purchase price consisting of $1.74 billion in cash and 7.69 million shares of our common stock, of which approximately 1.15 million shares were placed in an indemnity escrow. This transaction includes the acquisition of (i) approximately 100,306 gross (80,339 net) acres primarily in Pecos and Reeves counties for approximately $2.5 billion and (ii) midstream assets for approximately $47.6 million. We used the net proceeds from our December 2016 equity offering, net proceeds from our December 2016 debt offering, cash on hand and other financing sources to fund the cash portion of the purchase price for this acquisition.

Viper Equity Offerings

In January 2017, Viper 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. Viper received net proceeds from this offering of approximately $147.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which Viper used $120.5 million to repay the outstanding borrowings under its revolving credit agreement and the balance was used for general partnership purposes, which included additional acquisitions.

In July 2017, Viper 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. In this offering, we purchased 700,000 common units, an affiliate of the General Partner purchased 3,000,000 common units and certain officers and directors of our Company and the General Partner purchased an aggregate of 114,000 common units, in each case directly from the underwriters. Following this offering, we had an approximate 64% limited partner interest in Viper. Viper received net proceeds from this offering of approximately $232.5 million, after deducting underwriting discounts and commissions and estimated offering expenses, of which Viper used $152.8 million to repay all of the then-outstanding borrowings under Viper's revolving credit facility and the balance was used fund a portion of the purchase price for acquisitions and for general partnership purposes.

Operational Update

During the three months ended September 30, 2017, we drilled 42 gross (38 net) operated horizontal wells, 12 gross (12 net) of which were in the Delaware Basin and turned 24 gross (19 net) operated horizontal wells into production, of which seven gross (seven net) were wells in the Delaware Basin. During the nine months ended September 30, 2017, we drilled 106 gross (94 net) operated horizontal wells and turned 85 gross (71 net) operated horizontal wells to production. We also participated in the drilling of 12 gross (one net) wells and in the completion of 18 gross (two net) non-operated wells. We expect to turn between 35 to 40 gross operated horizontal wells to production during fourth quarter of 2017.

We are currently operating nine rigs and intend to operate between nine and ten drilling rigs during the remainder of 2017 across our asset base in the Midland and Delaware Basins, based on current commodity prices. We plan to operate six to seven of these rigs in the Midland Basin targeting horizontal development of the Wolfcamp and Spraberry formations, while the remainder of the rigs are expected to operate in the Delaware Basin targeting the Wolfcamp and Bone Spring formations.

In the Midland Basin, we continue to see positive well results from our core development areas in Midland, Glasscock, Howard, Andrews and Martin Counties. Assuming commodity prices at current levels, we anticipate operating one rig in Glasscock County, one rig in Howard County and three or more rigs in Midland, Martin and Andrews Counties through the remainder of 2017.

In the Delaware Basin, we are currently operating four drilling rigs, which we plan to maintain through the remainder of 2017 targeting the Wolfcamp and Bone Spring formations. Our early operated well results in the Delaware Basin have confirmed the productivity of the asset base, and we are focused on transferring our best practices on cost control from the Midland Basin to the Delaware Basin.

We continue to focus on low cost operations and best in class execution. In doing so, we are focused on controlling oilfield service costs as our service providers seek to increase pricing after two years of declining service costs during the downturn in the oil market. To combat rising service costs, we have looked to lock in pricing for dedicated activity levels and will continue to seek opportunities to control additional well cost where possible, including de-bundling of completion costs. We believe that our 2017 drilling and completion budget will cover potential increases in our service costs during the year.

The following table summarizes our average daily production for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Oil (Bbls)/d	61,720	32,618	55,212	29,398
Natural Gas (Mcf)/d	64,506	29,054	53,321	27,577
Natural Gas Liquids (Bbls)/d	12,558	7,463	10,526	6,048
Total average production per day (BOE)	85,029	44,923	74,624	40,042

Our average daily production for the three months ended September 30, 2017 as compared to the three months ended September 30, 2016 increased 40,106 BOE/d, or 89.3%.

Sources of Our Revenue

Our main source of revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or commodity prices.

The following table presents the breakdown of our revenues for the following periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Revenues				
Oil sales	87%	89%	88%	90%
Natural gas sales	5%	4%	5%	4%
Natural gas liquid sales	8%	7%	7%	6%
	100%	100%	100%	100%

Since our production consists primarily of oil, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 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 commodity prices may not only decrease our revenues, but also potentially the amount of oil and natural gas that we 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.

Results of Operations

The following table sets forth selected historical operating data for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands, except Bbl, Mcf and BOE amounts)			
Revenues				
Oil, natural gas liquids and natural gas	$ 299,237	$ 142,131	$ 799,169	$ 342,095
Lease bonus	322	—	2,507	—
Midstream services	1,694	—	4,241	—
Total revenues	301,253	142,131	805,917	342,095
Operating expenses				
Lease operating expenses	32,498	22,180	88,113	59,080
Production and ad valorem taxes	18,371	9,123	49,975	25,244
Gathering and transportation	3,476	2,843	9,110	8,064
Midstream services	4,445	—	7,127	—
Depreciation, depletion and amortization	87,579	44,746	221,681	126,686
Impairment of oil and natural gas properties	—	46,368	—	245,536
General and administrative expenses	11,888	9,908	37,524	32,411
Asset retirement obligation accretion	357	270	1,030	770
Total expenses	158,614	135,438	414,560	497,791
Income (loss) from operations	142,639	6,693	391,357	(155,696)
Interest expense	(9,192)	(10,234)	(29,662)	(30,266)
Other income	3	907	9,472	1,647
Gain (loss) on derivative instruments, net	(50,645)	2,034	20,376	(8,665)
Total other income (expense), net	(59,834)	(7,293)	186	(37,284)
Income (loss) before income taxes	82,805	(600)	391,543	(192,980)
Provision for income taxes	857	—	4,393	368
Net income (loss)	81,948	(600)	387,150	(193,348)
Net income (loss) attributable to non-controlling interest	8,924	1,630	19,448	(2,716)
Net income (loss) attributable to Diamondback Energy, Inc.	$ 73,024	$ (2,230)	$ 367,702	$ (190,632)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	(in thousands, except Bbl, Mcf and BOE amounts)			
Production Data:				
Oil (Bbls)	5,678,217	3,000,845	15,072,745	8,054,945
Natural gas (Mcf)	5,934,596	2,672,988	14,556,511	7,556,147
Natural gas liquids (Bbls)	1,155,336	686,563	2,873,626	1,657,189
Combined volumes (BOE)	7,822,652	4,132,906	20,372,456	10,971,492
Daily combined volumes (BOE/d)	85,029	44,923	74,624	40,042
Average Prices:				
Oil (per Bbl)	$ 45.62	$ 42.11	$ 46.71	$ 38.08
Natural gas (per Mcf)	2.51	2.37	2.58	1.91
Natural gas liquids (per Bbl)	21.87	13.76	20.05	12.63
Combined (per BOE)	38.25	34.39	39.23	31.18
Oil, hedged($ per Bbl)(1)	46.90	41.98	47.35	38.60
Natural gas, hedged ($ per MMbtu)(1)	2.64	2.37	2.67	1.91
Average price, hedged($ per BOE)(1)	39.28	34.30	39.77	31.56
Average Costs per BOE:				
Lease operating expense	$ 4.15	$ 5.37	$ 4.33	$ 5.38
Production and ad valorem taxes	2.35	2.21	2.45	2.30
Gathering and transportation expense	0.44	0.69	0.45	0.73
General and administrative - cash component	0.73	0.88	0.89	1.07
Total operating expense - cash	7.67	9.15	8.12	9.48
General and administrative - non-cash component	0.79	1.52	0.95	1.88
Depreciation, depletion and amortization	11.20	10.83	10.88	11.55
Interest expense	1.18	2.48	1.46	2.76
Total expenses	13.17	14.83	13.29	16.19
Average realized oil price ($/Bbl)	$ 45.62	$ 42.11	$ 46.71	$ 38.08
Average NYMEX ($/Bbl)	48.18	44.85	49.30	41.35
Differential to NYMEX	(2.56)	(2.74)	(2.59)	(3.27)
Average realized oil price to NYMEX	95%	94%	95%	92%
Average realized natural gas price ($/Mcf)	$ 2.51	$ 2.37	$ 2.58	$ 1.91
Average NYMEX ($/Mcf)	2.95	2.88	3.01	2.34
Differential to NYMEX	(0.44)	(0.51)	(0.43)	(0.43)
Average realized natural gas price to NYMEX	85%	82%	86%	82%
Average realized natural gas liquids price ($/Bbl)	$ 21.87	$ 13.76	$ 20.05	$ 12.63
Average NYMEX oil price ($/Bbl)	48.18	44.85	49.30	41.35
Average realized natural gas liquids price to NYMEX oil price	45%	31%	41%	31%

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices. Our calculation of such effects include gains and losses on cash settlements for commodity derivatives, which we do not designate for hedge accounting.

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

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $157.1 million, or 111%, to $299.2 million for the three months ended September 30, 2017 from $142.1 million for the three months ended September 30, 2016. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 40,106 BOE/d to 85,029 BOE/d during the three months ended September 30, 2017 from 44,923 BOE/d during the three months ended September 30, 2016. The total increase in revenue of approximately $157.1 million is largely attributable to higher oil, natural gas liquids and natural gas production volumes and higher average sales prices for the three months ended September 30, 2017 as compared to the three months ended September 30, 2016. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 2,677,372 Bbls of oil, 468,773 Bbls of natural gas liquids and 3,261,608 Mcf of natural gas for the three months ended September 30, 2017 as compared to the three months ended September 30, 2016.

The net dollar effect of the increases in prices of approximately $30.1 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $127.0 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change
			(in thousands)
Effect of changes in price:			
Oil	$ 3.51	5,678,217	$ 19,948
Natural gas	0.14	5,934,596	831
Natural gas liquids	8.11	1,155,336	9,370
Total revenues due to change in price			$ 30,149

	Change in production volumes(1)	Prior period Average Prices	Total net dollar effect of change
			(in thousands)
Effect of changes in production volumes:			
Oil	2,677,372	$ 42.11	$ 112,780
Natural gas	3,261,608	2.37	7,729
Natural gas liquids	468,773	13.76	6,448
Total revenues due to change in production volumes			126,957
Total change in revenues			$ 157,106

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

Lease Bonus Revenue. Lease bonus revenue was $0.3 million for the three months ended September 30, 2017 attributable to lease bonus payments to extend the term of one lease, reflecting an average bonus of $10,000 per acre. We had no lease bonus revenue for the three months ended September 30, 2016.

Midstream Services Revenue. Midstream services revenue was $1.7 million for the three months ended September 30, 2017. We had no midstream services revenue for the three months ended September 30, 2016. Our midstream services revenue represents fees charged to our joint interest owners and third parties for the transportation of oil and natural gas along with water gathering and related disposal facilities. These assets complement our operations in areas where we have significant production.

Lease Operating Expense. Lease operating expense was $32.5 million ($4.15 per BOE) for the three months ended September 30, 2017 as compared to $22.2 million ($5.37 per BOE) for the three months ended September 30, 2016. The decrease in lease operating expense per BOE was a result of non-recurring costs to increase baseline production offset by higher production volumes.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $18.4 million for the three months ended September 30, 2017, an increase of $9.2 million, or 101%, from $9.1 million for the three months ended September 30, 2016. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, among other factors, whereas production taxes are based upon current year commodity prices. During the three months ended September 30, 2017, our production and ad valorem taxes per BOE increased by $0.14 as compared to the three months ended September 30, 2016, primarily due to increased commodity prices and production volumes.

Midstream Services Expense. Midstream services expense was $4.4 million for the three months ended September 30, 2017. We had no midstream services expense for the three months ended September 30, 2016. Midstream services expense represents costs incurred to operate and maintain our oil and natural gas gathering and transportation systems, natural gas lift, compression infrastructure and water transportation facilities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $42.8 million, or 96%, to $87.6 million for the three months ended September 30, 2017 from $44.7 million for the three months ended September 30, 2016.

The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

	Three Months Ended September 30,	
	2017	**2016**
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$ 86,388	$ 44,340
Depreciation of midstream assets	830	60
Depreciation of other property and equipment	361	346
Depreciation, depletion and amortization expense	$ 87,579	$ 44,746
Oil and natural gas properties depreciation, depletion and amortization per BOE	$ 11.04	$ 10.73
Total depreciation, depletion and amortization per BOE	$ 11.20	$ 10.83

The increase in depletion of proved oil and natural gas properties of $42.0 million for the three months ended September 30, 2017 as compared to the three months ended September 30, 2016 resulted primarily from higher production levels and an increase in net book value on new reserves added.

Impairment of Oil and Natural Gas Properties. During the three months ended September 30, 2016, we recorded an impairment of oil and natural gas properties of $46.4 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 of oil and natural gas properties during the three months ended September 30, 2017.

General and Administrative Expense. General and administrative expense increased $2.0 million from $9.9 million for the three months ended September 30, 2016 to $11.9 million for the three months ended September 30, 2017. The increase was primarily due to an increase in salaries and benefits.

Net Interest Expense. Net interest expense for the three months ended September 30, 2017 was $9.2 million as compared to $10.2 million for the three months ended September 30, 2016, a decrease of $1.0 million. This decrease was primarily due to the issuance in October 2016 of new senior notes due 2024 with a lower interest rate than the senior notes which we redeemed in the fourth quarter of 2016 partially offset by the interest on the additional senior notes due 2025 that we issued in December 2016.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the three months ended September 30, 2017, we had a cash gain on settlement of derivative instruments of $8.0 million as compared to a cash loss on settlement of derivative instruments of $0.4 million for the three months ended September 30, 2016. For the three months ended September 30, 2017, we had a negative change in the fair value of open derivative instruments of $58.6 million as compared to a positive change of $2.4 million for the three months ended September 30, 2016.

Provision for Income Taxes. We recorded an income tax provision of $0.9 million for the three months ended September 30, 2017. We did not record an income tax provision or benefit for the three months ended September 30, 2016.

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

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues increased by approximately $457.1 million, or 134%, to $799.2 million for the nine months ended September 30, 2017 from $342.1 million for the nine months ended September 30, 2016. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 34,582 BOE/d to 74,624 BOE/d during the nine months ended September 30, 2017 from 40,042 BOE/d during the nine months ended September 30, 2016. The total increase in revenue of approximately $457.1 million is largely attributable to higher oil, natural gas liquids and natural gas production volumes and higher average sales prices for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 7,017,800 Bbls of oil, 1,216,437 Bbls of natural gas liquids and 7,000,364 Mcf of natural gas for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016.

The net dollar effect of the increases in prices of approximately $161.1 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $295.9 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change
			(in thousands)
Effect of changes in price:			
Oil	$ 8.63	15,072,745	$ 130,063
Natural gas	0.67	14,556,511	9,753
Natural gas liquids	7.42	2,873,626	21,322
Total revenues due to change in price			$ 161,138

	Change in production volumes(1)	Prior period Average Prices	Total net dollar effect of change
			(in thousands)
Effect of changes in production volumes:			
Oil	7,017,800	$ 38.08	$ 267,170
Natural gas	7,000,364	1.91	13,401
Natural gas liquids	1,216,437	12.63	15,365
Total revenues due to change in production volumes			295,936
Total change in revenues			$ 457,074

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

Lease Bonus Revenue. Lease bonus revenue was $2.5 million for the nine months ended September 30, 2017 attributable to lease bonus payments to extend the term of four leases, reflecting an average bonus of $3,257 per acre. We had no lease bonus revenue for the nine months ended September 30, 2016.

Midstream Services Revenue. Midstream services revenue was $4.2 million for the nine months ended September 30, 2017. We had no midstream services revenue for the nine months ended September 30, 2016. Our midstream services revenue represents fees charged to our joint interest owners and third parties for the transportation of oil and natural gas along with water gathering and related disposal facilities. These assets complement our operations in areas where we have significant production.

Lease Operating Expense. Lease operating expense was $88.1 million ($4.33 per BOE) for the nine months ended September 30, 2017 as compared to $59.1 million ($5.38 per BOE) for the nine months ended September 30, 2016. The decrease in lease operating expense per BOE was a result of non-recurring costs to increase baseline production offset by higher production volumes.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $50.0 million for the nine months ended September 30, 2017, an increase of $24.7 million, or 98%, from $25.2 million for the nine months ended September 30, 2016. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, among other factors, whereas production taxes are based upon current year commodity prices. During the nine months ended September 30, 2017, our production and ad valorem taxes per BOE increased by $0.15 as compared to the nine months ended September 30, 2016, primarily due to increased commodity prices and production volumes.

Midstream Services Expense. Midstream services expense was $7.1 million for the nine months ended September 30, 2017. We had no midstream services expense for the nine months ended September 30, 2016. Midstream services expense represents costs incurred to operate and maintain our oil and natural gas gathering and transportation systems, natural gas lift, compression infrastructure and water transportation facilities.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $95.0 million, or 75%, to $221.7 million for the nine months ended September 30, 2017 from $126.7 million for the nine months ended September 30, 2016.

The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

	Nine Months Ended September 30,	
	2017	**2016**
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$ 218,335	$ 125,475
Depreciation of midstream assets	2,261	179
Depreciation of other property and equipment	1,085	1,032
Depreciation, depletion and amortization expense	$ 221,681	$ 126,686
Oil and natural gas properties depreciation, depletion and amortization per BOE	$ 10.71	$ 11.46
Total depreciation, depletion and amortization per BOE	$ 10.88	$ 11.55

The increase in depletion of proved oil and natural gas properties of $92.9 million for the nine months ended September 30, 2017 as compared to the nine months ended September 30, 2016 resulted primarily from higher production levels and an increase in net book value on new reserves added.

Impairment of Oil and Gas Natural Properties. During the nine months ended September 30, 2016, we recorded an impairment of oil and natural gas properties of $245.5 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 of oil and natural gas properties during the nine months ended September 30, 2017.

General and Administrative Expense. General and administrative expense increased $5.1 million from $32.4 million for the nine months ended September 30, 2016 to $37.5 million for the nine months ended September 30, 2017. The increase was primarily due to an increase in salaries and benefits.

Net Interest Expense. Net interest expense for the nine months ended September 30, 2017 was $29.7 million as compared to $30.3 million for the nine months ended September 30, 2016, a decrease of $0.6 million. This decrease was primarily due to the issuance in October 2016 of new senior notes due 2024 with a lower interest rate than the senior notes which we redeemed in the fourth quarter of 2016 partially offset by the interest on the additional senior notes due 2025 that we issued in December 2016.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our consolidated statements of operations under the line item captioned "Gain (loss) on derivative instruments, net." For the nine months ended September 30, 2017 and 2016, we had a cash gain on settlement of derivative instruments of $11.0 million and $4.2 million, respectively. For the nine months ended September 30, 2017, we had a positive change in the fair value of open derivative instruments of $9.4 million as compared to a negative change of $12.9 million for the nine months ended September 30, 2016.

Provision for Income Taxes. We recorded an income tax provision of $4.4 million and $0.4 million for the nine months ended September 30, 2017 and 2016, respectively.

Liquidity and Capital Resources

Our primary sources of liquidity have been proceeds from our public equity offerings, borrowings under our revolving credit facility, proceeds from the issuance of the senior notes and cash flows from operations. Our primary uses of capital have been for the acquisition, development and exploration of oil and natural gas properties. As we pursue reserves and production growth, we regularly consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us.

Liquidity and Cash Flow

Our cash flows for the nine months ended September 30, 2017 and 2016 are presented below:

	Nine Months Ended September 30,	
	2017	**2016**
	(in thousands)	
Net cash provided by operating activities	$ 638,018	$ 226,346
Net cash used in investing activities	(2,764,725)	(982,040)
Net cash provided by financing activities	490,338	902,848
Net increase (decrease) in cash	$ (1,636,369)	$ 147,154

Operating Activities

Net cash provided by operating activities was $638.0 million for the nine months ended September 30, 2017 as compared to $226.3 million for the nine months ended September 30, 2016. The increase in operating cash flows is primarily the result of an increase in our oil and natural gas revenues due to an increase in average prices and production growth during the nine months ended September 30, 2017.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. 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. See "—Sources of our revenue" above.

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. Net cash used in investing activities was $2,764.7 million and $982.0 million during the nine months ended September 30, 2017 and 2016, respectively.

During the nine months ended September 30, 2017, we spent (a) $531.5 million on capital expenditures in conjunction with our development program, in which we drilled 106 gross (94 net) horizontal wells, completed 85 gross (71 net) horizontal wells and participated in the drilling of 12 gross (one net) non-operated wells in the Permian

Basin, (b) $22.5 million on additions to midstream assets, (c) $1,892.9 million on leasehold acquisitions, (d) $50.3 million for the acquisition of midstream assets and (e) $21.5 million for the purchase of other property and equipment.

During the nine months ended September 30, 2016, we spent $242.2 million on capital expenditures in conjunction with our drilling program and related infrastructure projects, in which we drilled 48 gross (38 net) horizontal wells, completed 39 gross (34 net) horizontal wells and participated in the drilling of 12 gross (four net) non-operated wells in the Permian Basin. We spent an additional $591.8 million on leasehold acquisitions, $137.8 million on royalty interest acquisitions and $9.8 million for the purchase of other property and equipment.

Our investing activities for the nine months ended September 30, 2017 and 2016 are summarized in the following table:

	Nine Months Ended September 30,	
	2017	**2016**
	(in thousands)	
Drilling, completion and infrastructure	$ (531,489)	$ (242,246)
Additions to midstream assets	(22,491)	(1,188)
Acquisition of leasehold interests	(1,892,864)	(591,785)
Acquisition of mineral interests	(370,855)	(137,782)
Acquisition of midstream assets	(50,279)	—
Purchase of other property and equipment	(21,534)	(9,805)
Proceeds from sale of property and equipment	3,584	1,566
Funds held in escrow	121,391	—
Equity investments	(188)	(800)
Net cash used in investing activities	$ (2,764,725)	$ (982,040)

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2017 and 2016 was $490.3 million and $902.8 million, respectively. During the nine months ended September 30, 2017, the amount provided by financing activities was primarily attributable to proceeds from Viper’s January and July 2017 equity offerings of $370.3 million as well as borrowings net of repayments of $149.5 million. The 2016 amount provided by financing activities was primarily attributable to the aggregate proceeds from our January and July 2016 equity offerings of $900.7 million, partially offset by repayments of net borrowings of $9.0 million under our credit facility.

2024 Senior Notes

On October 28, 2016, we issued $500.0 million in aggregate principal amount of 4.750% senior notes due 2024, which we refer to as the 2024 senior notes. The 2024 senior notes bear interest at a rate of 4.750% per annum, payable semi-annually, in arrears on May 1 and November 1 of each year, commencing on May 1, 2017 and will mature on November 1, 2024. All of our existing and future restricted subsidiaries that guarantee our revolving credit facility or certain other debt guarantee the 2024 senior notes; provided, however, that the 2024 senior notes are not guaranteed by Viper, Viper Energy Partners GP LLC, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of the our future unrestricted subsidiaries.

The 2024 senior notes were issued under, and are governed by, an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented. The 2024 indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

We may on any one or more occasions redeem some or all of the 2024 senior notes at any time on or after November 1, 2019 at the redemption prices (expressed as percentages of principal amount) of 103.563% for the 12-month period beginning on November 1, 2019, 102.375% for the 12-month period beginning on November 1, 2020, 101.188% for the 12-month period beginning on November 1, 2021 and 100.000% beginning on November 1, 2022 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to November 1, 2019, we may on any one or more occasions redeem all or a portion of the 2024 senior notes at a price equal to 100% of the principal amount of the 2024 senior notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to November 1, 2019, we may on any one or more occasions redeem the 2024 senior notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2024 senior notes issued prior to such date at a redemption price of 104.750%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

2025 Senior Notes

On December 20, 2016, we issued $500.0 million in aggregate principal amount of 5.375% senior notes due 2025, which we refer to as the 2025 senior notes. The 2025 senior notes bear interest at a rate of 5.375% per annum, payable semi-annually, in arrears on May 31 and November 30 of each year, commencing on May 31, 2017 and will mature on May 31, 2025. All of our existing and future restricted subsidiaries that guarantee our revolving credit facility or certain other debt guarantee the 2025 senior notes, provided, however, that the 2025 senior notes are not guaranteed by Viper, Viper Energy Partners GP LLC, Viper Energy Partners LLC or Rattler Midstream LLC, and will not be guaranteed by any of our future unrestricted subsidiaries.

The 2025 senior notes were issued under an indenture, dated as of December 20, 2016, among us, the guarantors party thereto and Wells Fargo, as the trustee. The 2025 Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit our ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting our restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of our assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of our subsidiaries as unrestricted subsidiaries.

We may on any one or more occasions redeem some or all of the 2025 senior notes at any time on or after May 31, 2020 at the redemption prices (expressed as percentages of principal amount) of 104.031% for the 12-month period beginning on May 31, 2020, 102.688% for the 12-month period beginning on May 31, 2021, 101.344% for the 12-month period beginning on May 31, 2022 and 100.000% beginning on May 31, 2023 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. Prior to May 31, 2020, we may on any one or more occasions redeem all or a portion of the 2025 senior notes at a price equal to 100% of the principal amount of the 2025 senior notes plus a “make-whole” premium and accrued and unpaid interest to the redemption date. In addition, any time prior to May 31, 2020, we may on any one or more occasions redeem the 2025 senior notes in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2025 senior notes issued prior to such date at a redemption price of 105.375%, plus accrued and unpaid interest to the redemption date, with an amount equal to the net cash proceeds from certain equity offerings.

As required under the terms of the registration rights agreements relating to the 2024 senior notes and the 2025 senior notes, we filed with the SEC our Registration Statement on Form S-4, as amended, relating to the exchange offers of the 2024 senior notes and the 2025 senior notes for substantially identical notes registered under the Securities Act. The Registration Statement was declared effective by the SEC on June 21, 2017 and we closed these exchange offers on July 27, 2017, in which all privately placed 2024 senior notes and 2025 senior notes were exchanged for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act.

Second Amended and Restated Credit Facility

Our second amended and restated credit agreement, dated November 1, 2013, as amended, with a syndicate of banks, including Wells Fargo, as administrative agent, sole book runner and lead arranger, provides for a revolving credit facility in the maximum amount of $2.0 billion. As of September 30, 2017, the borrowing base was set at $1.5 billion, although we had elected a commitment amount of $750.0 million. As of September 30, 2017, we had $234.5 million in outstanding borrowings and $515.5 million available for future borrowings under this facility.

In connection with our fall 2017 redetermination which is expected to be completed in November 2017, the lead lender has proposed an increase in our borrowing base under our facility from $1.5 billion to $1.8 billion, and we intend to increase our elected commitment amount from $750.0 million to $1.0 billion. The proposed increase in our borrowing base is subject to approval of the additional lenders within the syndicate.

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 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 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), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2018.

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

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

The covenant prohibiting additional indebtedness, as amended in December 2016, allows for the issuance of unsecured debt of up to $1.0 billion in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of September 30, 2017, we had $1.0 billion in aggregate principal amount of senior notes outstanding.

As of September 30, 2017, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. With certain specified exceptions, the terms and provisions of our revolving credit facility generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Viper’s Facility-Wells Fargo Bank

Viper is a 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. 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 Viper had $35.5 million in outstanding borrowings and $279.5 million available for future borrowings under this facility.

In connection with Viper's fall 2017 redetermination which is expected to be completed in November 2017, the lead lender has proposed an increase in Viper's borrowing base under its facility from $315 million to $400 million. The proposed increase in Viper’s borrowing base is subject to approval of the additional lenders within the syndicate.

The outstanding borrowings under Viper’s credit agreement bear interest at a rate elected by Viper 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 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. Viper 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 Viper and its subsidiaries.

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 Viper's revolving credit facility upon the occurrence and during the continuance of any event of default. Viper'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.

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2017 capital budget for drilling and infrastructure of approximately $800.0 million to $950.0 million, representing an increase of 126% over our 2016 capital budget. We have now narrowed that range to approximately $850.0 million to $900.0 million. We estimate that, of these expenditures, approximately:

- $725.0 million to $750.0 million will be spent on drilling and completing 120 to 125 gross (103 to 108 net) operated horizontal wells focused in the Midland and Delaware Basins and participating in non-operated activity; and

- $125.0 million to $150.0 million will be spent on infrastructure and other expenditures, including aggregate investments of $75.0 million in midstream assets on our recently acquired properties in the Delaware Basin, excluding the cost of any leasehold and mineral interest acquisitions.

During the nine months ended September 30, 2017, our aggregate capital expenditures for our development program were $531.5 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the nine months ended September 30, 2017, we spent approximately $1.9 billion in cash on acquisitions of leasehold interests and mineral acres. During 2018, we expect to transfer certain of our mineral acres to Viper.

The amount and timing of these capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. We are currently operating nine rigs and four completion crews. We will continue monitoring commodity prices and overall market conditions and can adjust our rig cadence up or down in response to changes in commodity prices and overall market conditions.

Based upon current oil and natural gas price and production expectations for 2017, we believe that our cash flow from operations, cash on hand and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2017. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. Further, our 2017 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

We monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control. If we require additional capital, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financing, asset sales, offerings of debt and or equity securities or other means. We cannot assure you that the needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves. If there is further decline in commodity prices, our revenues, cash flows, results of operations, liquidity and reserves may be materially and adversely affected.

Contractual Obligations

Except as discussed in Note 15 of the Notes to the Consolidated Financial Statements of this report, there were no material changes to 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 in 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 had no off-balance sheet arrangements as of September 30, 2017. Please read Note 15 included in Notes to the Combined Consolidated Financial Statements set forth in Part I, Item 1 of this report, for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

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

We use price swap derivatives, including basis swaps and costless collars, to reduce price volatility associated with certain of our oil and natural gas sales. With respect to these fixed price swap contracts, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. Our derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on NYMEX West Texas Intermediate pricing and Crude Oil - Brent and with natural gas derivative settlements based on NYMEX Henry Hub pricing.

At September 30, 2017 and December 31, 2016, we had a net liability derivative position of $12.5 million and $22.6 million, respectively, related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of September 30, 2017, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position to $74.2 million, an increase of $61.6 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $49.1 million, an increase of $61.6 million. However, any cash derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $49.7 million at September 30, 2017) and receivables from the sale of our oil and natural gas production (approximately $104.0 million at September 30, 2017).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the nine months ended September 30, 2017, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (33%); Koch Supply & Trading LP (20%); and Enterprise Crude Oil LLC (11%). For the nine months ended September 30, 2016, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (50%); Enterprise Crude Oil LLC (13%); and Koch Supply & Trading LP (12%). No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At September 30, 2017, we had six customers that represented approximately 82% of our total joint operations receivables. At December 31, 2016, we had three customers that represented approximately 75% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.50% 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.

As of September 30, 2017, we had $234.5 million in outstanding borrowings under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 2.99%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $2.3 million based on an aggregate of $234.5 million outstanding under our revolving credit facility as of September 30, 2017.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or 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 our Chief Executive Officer and Chief Financial Officer, 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 our Chief Executive Officer and Chief Financial Officer, 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 our evaluation, our Chief Executive Officer and Chief Financial Officer 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

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, including workers' compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

ITEM 1A. RISK FACTORS

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

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Registration Rights Agreement, dated as of October 11, 2012, by and between the Company and DB Energy Holdings LLC (incorporated by reference to Exhibit 4.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.3	Investor Rights Agreement, dated as of October 11, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.4	Indenture, dated as of October 28, 2016, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Diamondback Energy, Inc.'s 4.750 % Senior Notes due 2024) (incorporated by reference to Exhibit 4.1 to the Form 8-K , File No. 001-35700, filed by the Company with the SEC on November 2, 2016).
4.5	Indenture, dated as of December 20, 2016, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (including the form of Diamondback Energy, Inc.'s 5.375% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 21, 2016).
4.6	Registration Rights Agreement, dated as of February 28, 2017, by and among Diamondback Energy, Inc., Brigham Resources, LLC, Brigham Resources Operating, LLC and Brigham Resources Upstream Holdings, LP (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 6, 2017).
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant 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.
32.2**	Certification of Chief Financial Officer of the Registrant 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.

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* Filed herewith.

** The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Annual Report on Form 10-K pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed "filed" by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

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.

		DIAMONDBACK ENERGY, INC.
Date:	November 7, 2017	/s/ Travis D. Stice
		Travis D. Stice Chief Executive Officer (Principal Executive Officer)
Date:	November 7, 2017	/s/ Teresa L. Dick
		Teresa L. Dick Chief Financial Officer (Principal Financial and Accounting Officer)

EXHIBIT 31.1

CERTIFICATION

I, Travis D. Stice, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Diamondback Energy, Inc.
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ Travis D. Stice

Travis D. Stice
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Teresa L. Dick, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of Diamondback Energy, Inc.

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 7, 2017

/s/ Teresa L. Dick

Teresa L. Dick
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF PERIOD REPORT

In connection with the Quarterly Report on Form 10-Q of Diamondback Energy, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Travis D. Stice, Chief Executive Officer of Diamondback Energy, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) The Report fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: November 7, 2017

/s/ Travis D. Stice

Travis D. Stice

Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION OF PERIOD REPORT

In connection with the Quarterly Report on Form 10-Q of Diamondback Energy, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Teresa L. Dick, Chief Financial Officer of Diamondback Energy, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

(1) the Report fully complies with the requirements of Section 13 (a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date:	November 7, 2017	/s/ Teresa L. Dick
		Teresa L. Dick
		Chief Financial Officer