Diamondback Energy, Inc.
Form 10-Q
August 09, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ýQUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2018
OR
oTRANSITION 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 (State or Other Jurisdiction of Incorporation or Organization)	45-4502447 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas	79701
(Address of Principal Executive Offices)	(Zip Code)

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ý 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 ý
As of August 3, 2018, 98,621,440 shares of the registrant’s common stock were outstanding.

DIAMONDBACK ENERGY, INC.
FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2018
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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.
Mb/d	Thousand barrels per day.
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.
Operating Company	Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of the Partnership.
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, 2017 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, including our pending acquisition of certain leasehold acres and other assets from Ajax Recourses, LLC discussed elsewhere in this report;
- 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.

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

	June 30, 2018	December 31, 2017
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$113,927	$112,446
Accounts receivable:		
Joint interest and other	91,036	73,038
Oil and natural gas sales	167,854	158,575
Inventories	13,264	9,108
Derivative instruments	—	531
Prepaid expenses and other	7,266	4,903
Total current assets	393,347	358,601
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($4,286,320 and $4,105,865 excluded from amortization at June 30, 2018 and December 31, 2017, respectively)	10,315,425	9,232,694
Midstream assets	343,387	191,519
Other property, equipment and land	85,472	80,776
Accumulated depletion, depreciation, amortization and impairment	(2,401,240)	(2,161,372)
Net property and equipment	8,343,044	7,343,617
Funds held in escrow	—	6,304
Deferred tax asset	72,049	—
Investment in real estate, net	108,564	—
Other assets	37,391	62,463
Total assets	$8,954,395	$7,770,985
Liabilities and Stockholders’ Equity		
Current liabilities:		
Accounts payable-trade	$73,974	$94,590
Accrued capital expenditures	369,957	221,256
Other accrued liabilities	94,266	92,512
Revenues and royalties payable	77,550	68,703
Derivative instruments	111,330	100,367
Total current liabilities	727,077	577,428
Long-term debt	1,967,074	1,477,347
Derivative instruments	8,514	6,303
Asset retirement obligations	21,780	20,122
Deferred income taxes	217,476	108,048
Other long term liabilities	7	—
Total liabilities	2,941,928	2,189,248
Commitments and contingencies (Note 16)		
Stockholders’ equity:		
	986	982

Common stock, $0.01 par value, 200,000,000 shares authorized, 98,619,628 issued and outstanding at June 30, 2018; 98,167,289 issued and outstanding at December 31, 2017		
Additional paid-in capital	5,307,358	5,291,011
Retained earnings (accumulated deficit)	323,105	(37,133)
Total Diamondback Energy, Inc. stockholders’ equity	5,631,449	5,254,860
Non-controlling interest	381,018	326,877
Total equity	6,012,467	5,581,737
Total liabilities and equity	$8,954,395	$7,770,985

See accompanying notes to consolidated financial statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(In thousands, except per share amounts)			
Revenues:				
Oil sales	$460,437	$237,884	$879,705	$444,958
Natural gas sales	11,365	12,693	25,743	22,615
Natural gas liquid sales	43,135	16,857	76,248	32,359
Lease bonus	928	583	928	2,185
Midstream services	7,983	1,417	19,378	2,547
Other operating income	2,425	—	4,466	—
Total revenues	526,273	269,434	1,006,468	504,664
Costs and expenses:				
Lease operating expenses	42,647	28,989	79,992	55,615
Production and ad valorem taxes	32,202	15,879	59,506	31,604
Gathering and transportation	6,813	3,015	11,098	5,634
Midstream services	17,601	1,828	28,790	2,682
Depreciation, depletion and amortization	129,867	75,173	245,083	134,102
General and administrative expenses (including non-cash equity-based compensation, net of capitalized amounts, of $5,650 and $6,168 for the three months ended June 30, 2018 and 2017, respectively, and $13,101 and $13,231 for the six months ended June 30, 2018 and 2017, respectively)	14,529	11,892	30,854	25,636
Asset retirement obligation accretion	365	350	720	673
Other operating expense	946	—	1,476	—
Total costs and expenses	244,970	137,126	457,519	255,946
Income from operations	281,303	132,308	548,949	248,718
Other income (expense):				
Interest expense, net	(17,096)	(8,245)	(30,797)	(20,470)
Other income, net	84,472	8,324	87,208	9,469
Gain (loss) on derivative instruments, net	(58,587)	33,320	(90,932)	71,021
Gain on revaluation of investment	4,465	—	5,364	—
Total other income (expense), net	13,254	33,399	(29,157)	60,020
Income before income taxes	294,557	165,707	519,792	308,738
Provision for (benefit from) income taxes	(6,607)	1,579	40,474	3,536
Net income	301,164	164,128	479,318	305,202
Net income attributable to non-controlling interest	82,018	5,723	97,360	10,524
Net income attributable to Diamondback Energy, Inc.	$219,146	$158,405	$381,958	$294,678
Earnings per common share:				
Basic	$2.22	$1.61	$3.87	$3.08
Diluted	$2.22	$1.61	$3.87	$3.07
Weighted average common shares outstanding:				
Basic	98,614	98,142	98,584	95,665
Diluted	98,797	98,354	98,820	95,925

Dividends declared per share	$0.125	$—	$0.250	$—

See accompanying notes to consolidated financial statements.

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	(In thousands)					
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		—	—	—	147,492	147,492
Unit-based compensation		—	—	—	1,537	1,537
Common units issued for acquisition		—	—	—	3,050	3,050
Stock-based compensation		—	15,939	—	—	15,939
Distribution to non-controlling interest		—	—	—	(14,123)	(14,123)
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	299	3	355	—	—	358
Net income		—	—	294,678	10,524	305,202
Balance June 30, 2017	98,129	$ 981	$5,041,359	$ (224,716)	$ 469,310	$5,286,934
Balance December 31, 2017	98,167	$ 982	$5,291,011	$ (37,133)	$ 326,877	$5,581,737
Impact of adoption of ASU 2016-01, net of tax		—	—	(9,393)	(6,671)	(16,064)
Unit-based compensation		—	—	—	1,740	1,740
Stock-based compensation		—	16,351	—	—	16,351
Distribution to non-controlling interest		—	—	—	(38,288)	(38,288)
Dividend paid		—	—	(12,327)	—	(12,327)
Exercise of stock options and vesting of restricted stock units	452	4	(4)	—	—	—
Net income		—	—	381,958	97,360	479,318
Balance June 30, 2018	98,620	$ 986	$5,307,358	$ 323,105	$ 381,018	$6,012,467

See accompanying notes to consolidated financial statements.

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

	Six Months Ended June 30, 2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 479,318	$ 305,202
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	39,966	2,334
Asset retirement obligation accretion	720	673
Depreciation, depletion and amortization	245,083	134,102
Amortization of debt issuance costs	1,434	1,811
Change in fair value of derivative instruments	13,705	(68,010)
Income from equity investment	—	(156)
Gain on revaluation of investment	(5,358)	—
Equity-based compensation expense	13,101	13,231
Loss (gain) on sale of assets, net	3,123	(67)
Changes in operating assets and liabilities:		
Accounts receivable	(1,067)	(36,137)
Accounts receivable-related party	—	289
Restricted cash	—	500
Inventories	(17,983)	(3,059)
Prepaid expenses and other	(2,926)	(4,966)
Accounts payable and accrued liabilities	(1,299)	26,782
Accounts payable and accrued liabilities-related party	—	(2)
Accrued interest	(11,953)	(7,756)
Income tax payable	(358)	1,017
Revenues and royalties payable	8,847	28,643

Net cash provided by operating activities	764,353		394,431	
Cash flows from investing activities:				
Additions to oil and natural gas properties	(650,058	)	(291,767	)
Additions to midstream assets	(94,503	)	(4,444	)
Purchase of other property, equipment and land	(3,978	)	(13,825	)
Acquisition of leasehold interests	(101,216	)	(1,860,980	)
Acquisition of mineral interests	(253,102	)	(122,679	)
Acquisition of midstream assets	—		(50,279	)
Proceeds from sale of assets	3,879		1,295	
Investment in real estate	(110,480	)	—	
Funds held in escrow	10,989		121,391	
Equity investments	(125	)	(188	)
Net cash used in investing activities	(1,198,594	)	(2,221,476	)
Cash flows from financing activities:				
Proceeds from borrowings under credit facility	569,000		266,000	
Repayment under credit facility	(388,000	)	(221,000	)
Proceeds from senior notes	312,000		—	
Debt issuance costs	(4,375	)	(1,605	)
Public offering costs	(2,288	)	(296	)
Proceeds from public offerings	—		147,725	
Proceeds from exercise of stock options	—		358	
Dividends to stockholders	(12,327	)	—	
Distributions to non-controlling interest	(38,288	)	(14,123	)

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

	Six Months Ended June 30,	
	2018	2017
Net cash provided by financing activities	435,722	177,059
Net increase (decrease) in cash and cash equivalents	1,481	(1,649,986)
Cash and cash equivalents at beginning of period	112,446	1,666,574
Cash and cash equivalents at end of period	$113,927	$16,588
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$44,199	$26,500
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$148,701	$93,415
Capitalized stock-based compensation	$4,990	$4,244
Common stock issued for oil and natural gas properties	$—	$809,173
Asset retirement obligations acquired	$39	$2,180

See accompanying notes to 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 June 30, 2018, 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, Rattler Midstream LLC (formerly known as White Fang Energy LLC), a Delaware limited liability company, and Tall City Towers 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 (the "Operating 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 June 30, 2018, the Company owned approximately 64% of the Partnership's total units outstanding. 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, 2017, 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 assumed, equity-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Investments

The Partnership has an equity interest in a limited partnership that is so minor that the Partnership has no influence over the limited partnership’s operating and financial policies. This interest was acquired during the year ended December 31, 2014 and is accounted for under the cost method. Effective January 1, 2018, the Partnership adopted Accounting Standards Update 2016-01 which requires the Partnership to measure this investment at fair value which resulted in a downward adjustment of $18.7 million to record the impact of this adoption. For the three months and six months ended June 30, 2018, the Partnership recorded a gain of $4.5 million and $5.4 million, respectively, which then increased the Partnership’s investment balance to $20.4 million, which is included in other assets in the accompanying consolidated balance sheets.

New Accounting Pronouncements

Recently Adopted Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, “Revenue from Contracts with Customers”. This standard included a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services. Among other things, the standard also eliminated industry-specific revenue guidance, required enhanced disclosures about revenue, provided guidance for transactions that were not previously addressed comprehensively and improved guidance for multiple-element arrangements. The Company adopted this Accounting Standards Update effective January 1, 2018 using the modified retrospective approach. The Company utilized a bottom-up approach to analyze the impact of the new standard by reviewing its current accounting policies and practices to identify potential differences that would result from applying the requirements of the new standard to its revenue contracts and the impact of adopting this standards update on its total revenues, operating income and its consolidated balance sheet. The adoption of this standard did not result in a cumulative-effect adjustment.

In January 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-01, “Financial Instruments–Overall”. This update applies to any entity that holds financial assets or owes financial liabilities. This update requires equity investments (except for those accounted for under the equity method or those that result in consolidation of the investee) to be measured at fair value with changes in fair value recognized in net income. The Partnership adopted this standard effective January 1, 2018 by means of a negative cumulative-effect adjustment totaling $18.7 million.

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. The Company adopted this update effective

January 1, 2018 using the retrospective transition method. Adoption of this standard did not have an effect on the presentation on the Statement of Cash Flows.

In November 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-18, “Statement of Cash Flows - Restricted Cash”. This update affects entities that have restricted cash or restricted cash equivalents. The Company adopted this update effective January 1, 2018. The adoption of this update did not have an effect on the presentation on the Statement of Cash Flows.

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

Accounting Pronouncements Not Yet Adopted

In February 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-02, “Leases”. This update applies to any entity that enters into a lease, with some specified scope exemptions. Under this update, a lessee should recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. While there were no major changes to the lessor accounting, changes were made to align key aspects with the revenue recognition guidance. This update will be effective for public entities for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. 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 January 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-01, “Leases - Land Easement Practical Expedient for Transition to Topic 842”. This update applies to any entity that holds land easements. The update allows entities to adopt a practical expedient to not evaluate existing or expired land easements under Topic 842 that were not previously accounted for as leases under the current leases guidance. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. The Company believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity.

In June 2016, the Financial Accounting Standards Board issued Accounting Standards Update 2016-13, “Financial Instruments - Credit Losses”. This update affects entities holding financial assets and net investment in leases that are not accounted for at fair value through net income. The amendments affect loans, debt securities, trade receivables, net investments in leases, off-balance sheet credit exposures, reinsurance receivables, and any other financial assets not excluded from the scope that have the contractual right to receive cash. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. This update will be applied through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The 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 June 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-07, “Stock Compensation - Improvements to Nonemployee Share-Based Payment Accounting”. This update applies the existing employee guidance to nonemployee share-based transactions, with the exception of specific guidance related to the attribution of compensation cost. This update will be effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. The Company is currently evaluating the impact of the adoption of this update, but does not believe it will have a material impact.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Revenue from Contracts with Customers

Sales of oil, natural gas and natural gas liquids are recognized at the point control of the product is transferred to the customer. Virtually all of the pricing provisions in the Company's contracts are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, the quality of the oil or natural gas and the prevailing supply and demand conditions. As a result, the price of the oil, natural gas and natural gas liquids fluctuates to remain competitive with other available oil, natural gas and natural gas liquids supplies.

Oil sales

The Company's oil sales contracts are generally structured where it delivers oil to the purchaser at a contractually agreed-upon delivery point at which the purchaser takes custody, title and risk of loss of the product. Under this arrangement, the Company or a third party transports the product to the delivery point and receives a specified index price from the purchaser with no deduction. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the price received from the purchaser. Oil revenues are recorded net of any third-party transportation fees and other applicable differentials in the Company’s consolidated statements of operations.

Natural gas and natural gas liquids sales

Under the Company’s natural gas processing contracts, it delivers natural gas to a midstream processing entity at the wellhead, battery facilities or the inlet of the midstream processing entity’s system. The midstream processing entity gathers and processes the natural gas and remits proceeds to the Company for the resulting sales of natural gas liquids and residue gas. In these scenarios, the Company evaluates whether it is the principal or the agent in the transaction. For those contracts where the Company has concluded it is the principal and the ultimate third party is its customer, the Company recognizes revenue on a gross basis, with transportation, gathering, processing, treating and compression fees presented as an expense in its consolidated statements of operations.

In certain natural gas processing agreements, the Company may elect to take its residue gas and/or natural gas liquids in-kind at the tailgate of the midstream entity’s processing plant and subsequently market the product. Through the marketing process, the Company delivers product to the ultimate third-party purchaser at a contractually agreed-upon delivery point and receives a specified index price from the purchaser. In this scenario, the Company recognizes revenue when control transfers to the purchaser at the delivery point based on the index price received from the purchaser. The gathering, processing, treating and compression fees attributable to the gas processing contract, as well as any transportation fees incurred to deliver the product to the purchaser, are presented as transportation, gathering, processing, treating and compression expense in its consolidated statements of operations.

Midstream Revenue

Substantially all revenues from gathering, compression, water handling, disposal and treatment operations are derived from intersegment transactions for services Rattler Midstream LLC (“Rattler”) provides to exploration and production operations. The portion of such fees shown in the Company’s consolidated financial statements represent amounts charged to interest owners in the Company’s operated wells, as well as fees charged to other third parties for water handling and treatment services provided by Rattler or usage of Rattler’s gathering and compression systems. For gathering and compression revenue, Rattler satisfies its performance obligations and recognizes revenue when low pressure volumes are delivered to a specified delivery point. Revenue is recognized based on the per MMbtu gathering fee or a per barrel gathering fee charged by Rattler in accordance with the gathering and compression agreement. For water handling and treatment revenue, Rattler satisfies its performance obligations and recognizes revenue when the fresh water volumes have been delivered to the fracwater meter for a specified well pad and the wastewater volumes have been metered downstream of the Company’s facilities. For services contracted through third party providers, Rattler’s performance obligation is satisfied when the service performed by the third party provider has been completed. Revenue is recognized based on the per barrel fresh water delivery or a wastewater gathering and disposal fee charged by Rattler in accordance with the water services agreement.

Transaction price allocated to remaining performance obligations

The Company’s product sales contracts do not originate until production occurs and, therefore, are not considered to exist beyond each days’ production. Therefore, there are no remaining performance obligation under any of our product sales contracts.

Contract balances

Under the Company's product sales contracts, it has the right to invoice its customers once the performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's product sales contracts do not give rise to contract assets or liabilities under Accounting Standards Codification 606.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, settlement statements for certain natural gas and natural gas liquids sales may not be received for 30 to 90 days after the date

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production is delivered, and as a result, the Company is required to estimate the amount of production delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. The Company has existing internal controls for its revenue estimation process and related accruals, and any identified differences between its revenue estimates and actual revenue received historically have not been significant. For the three months ended June 30, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Company believes that the pricing provisions of its oil, natural gas and natural gas liquids contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the revenue related to expected sales volumes and prices for those properties are estimated and recorded.

4. ACQUISITIONS

On January 31, 2018, Tall City Towers LLC, a subsidiary of the Company, completed its acquisition of the Fasken Center office buildings in Midland, TX where the Company’s corporate offices are located for a net purchase price of $109.7 million.

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 included 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 and royalties payable	(9,650)
Asset retirement obligations	(1,550)
Total fair value of net assets	$2,549,599

The Company included in its consolidated statements of operations revenues of $48.0 million and direct operating expenses of $6.9 million for the period from February 28, 2017 to June 30, 2017 due to the acquisition.

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Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the three months and six months ended June 30, 2017 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 June 30, 2017	Six Months Ended June 30, 2017
	(in thousands, except per share amounts)	
Revenues	$269,434	$527,593
Income from operations	132,308	263,060
Net income	164,128	310,414
Basic earnings per common share	1.61	3.24
Diluted earnings per common share	1.61	3.24

5. 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 and the Eagle Ford Shale. Viper Energy Partners GP LLC, a fully-consolidated subsidiary of Diamondback, serves as the general partner of the Partnership. As of June 30, 2018, the Company owned approximately 64% of the Partnership’s total units outstanding.

Recapitalization, Tax Status Election and Related Transactions by Viper

In March 2018, the Partnership announced that the Board of Directors of the General Partner had unanimously approved a change of the Partnership’s federal income tax status from that of a pass-through partnership to that of a taxable entity via a “check the box” election. In connection with making this election, on May 9, 2018 the Partnership (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of the Operating Company, (iii) amended and restated its existing registration rights agreement with the Company and (iv) entered into an exchange agreement with the Company, the General Partner and the Operating Company. Simultaneously with the effectiveness of these agreements, the Company delivered and assigned to the Partnership the 73,150,000 common units the Company owned in exchange for (i) 73,150,000 of the Partnership’s newly-issued Class B units and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018 (the “Recapitalization Agreement”). Immediately following that exchange, the Partnership continued to be the managing member of the Operating Company, with sole control of its operations, and owned approximately 36% of the outstanding units issued by the Operating Company, and the Company owned the remaining approximately 64% of the outstanding units issued by the Operating Company. The Operating Company units and the Partnership's Class B units owned by the Company are exchangeable from time to time for the Partnership's common units (that is, one Operating Company unit and one Partnership Class B unit, together, will be exchangeable for one Partnership common unit).

On May 10, 2018, the change in the Partnership's income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to the Partnership in respect of its general partner interest and (ii) the Company made a cash capital contribution of $1.0 million to the Partnership in respect of the Class B units. The Company, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, the Company also exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of the Partnership and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B units. The General Partner continues to serve as the Partnership's general partner and the Company continues to control the Partnership. After the effectiveness of the tax status election and the completion of related transactions, the Partnership's minerals business continues to be conducted through the Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. This structure is anticipated to provide significant benefits to the Partnership's business, including operational effectiveness, acquisition and disposition transactional planning flexibility and income tax efficiency. For additional information regarding the tax status election and related transactions, please refer to the Partnership's Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018 and the Partnership's Current Report on Form 8-K filed with the SEC on May 15, 2018.

Partnership Agreement

The second amended and restated agreement of limited partnership, dated as of May 9, 2018, as amended as of May 10, 2018 (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 ended June 30, 2018 and 2017, the General Partner allocated $0.6 million to the Partnership. For the six months ended June 30, 2018 and 2017, the General Partner allocated $1.2 million to the Partnership.

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. For the three months and six months ended June 30, 2018, the Partnership accrued state income tax expense of $0.2 million for its share of Texas margin tax for which the Partnership's results are included in a combined tax return filed by Diamondback.

Other Agreements

See Note 12—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 9—Debt for a description of this credit facility.

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6. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	June 30, 2018	December 31, 2017
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$6,029,105	$5,126,829
Not subject to depletion	4,286,320	4,105,865
Gross oil and natural gas properties	10,315,425	9,232,694
Accumulated depletion	(1,237,781)	(1,009,893)
Accumulated impairment	(1,143,498)	(1,143,498)
Oil and natural gas properties, net	7,934,146	7,079,303
Midstream assets	343,387	191,519
Other property, equipment and land	85,472	80,776
Accumulated depreciation	(19,961)	(7,981)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$8,343,044	$7,343,617

Balance of costs not subject to depletion:	
Incurred in 2018	$374,515
Incurred in 2017	2,720,793
Incurred in 2016	717,065
Incurred in 2015	239,745
Incurred in 2014	234,202
Total not subject to depletion	$4,286,320

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 $6.7 million and $5.1 million for the three months ended June 30, 2018 and 2017, respectively, and $13.7 million and $10.2 million for the six months ended June 30, 2018 and 2017, 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.

At June 30, 2018, there was $90.0 million in exploration costs and development costs and $35.5 million in capitalized interest that was not subject to depletion. At December 31, 2017, there were $26.0 million in exploration costs and development costs and $22.1 million in capitalized interest that was not subject to depletion.

7. ASSET RETIREMENT OBLIGATIONS

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

	Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Asset retirement obligations, beginning of period	$21,285	$17,422
Additional liabilities incurred	1,535	990
Liabilities acquired	39	2,180
Liabilities settled	(1,420)	(149)
Accretion expense	720	673
Revisions in estimated liabilities	15	(2)
Asset retirement obligations, end of period	22,174	21,114
Less current portion	394	1,575
Asset retirement obligations - long-term	$21,780	$19,539

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.

8. EQUITY METHOD INVESTMENTS

In October 2014, the Company obtained a 25% interest in HMW Fluid Management LLC ("HMW 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. On June 30, 2018, HMW LLC's operating agreement was amended effective January 1, 2018. As a result of the amendment, the Company will no longer recognize an equity investment in HMW LLC but will instead consolidate its interests in the net assets of HMW LLC. In exchange for the Company's 25% investment, the Company received a

50% undivided ownership interest in two of the four salt water disposal wells and associated assets previously owned by HMW LLC. The Company’s basis in the assets is equivalent to its basis in the equity investment in HMW LLC. During the six months ended June 30, 2017, the Company invested $0.2 million in this entity and recorded $0.2 million, which is the Company’s share of HMW LLC’s net income, bringing its total investment to $6.7 million at June 30, 2017.

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9. DEBT

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

	June 30, 2018	December 31, 2017
	(in thousands)	
4.750 % Senior Notes due 2024	$500,000	$500,000
5.375 % Senior Notes due 2025	800,000	500,000
Unamortized debt issuance costs	(15,736)	(13,153)
Unamortized premium costs	11,310	—
Revolving credit facility	321,500	397,000
Partnership revolving credit facility	350,000	93,500
Total long-term debt	$1,967,074	$1,477,347

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

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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.

On January 29, 2018, the Company issued $300.0 million aggregate principal amount of new 5.375% Senior Notes due 2025 (the “New 2025 Notes”) as additional notes under, and subject to the terms of, the 2025 Indenture. The New 2025 Notes were issued in a transaction exempt from the registration requirements under the Securities Act. The Company received approximately $308.4 million in net proceeds, after deducting the initial purchaser’s discount and its estimated offering expenses, but disregarding accrued interest, from the issuance of the New 2025 Notes. The Company used the net proceeds from the issuance of the New 2025 Notes to repay a portion of the outstanding borrowings under its revolving credit facility.

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 the Company’s 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 (including the New 2025 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 (including the New 2025 Notes) at a price equal to 100% of the principal amount of the 2025 Senior Notes (including the New 2025 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 (including the New 2025 Notes) in an aggregate principal amount not to exceed 35% of the aggregate principal amount of the 2025 Senior Notes (including the New 2025 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.

The Company’s Credit Facility

The Company and Diamondback O&G LLC, as borrower, entered into the second amended and restated credit agreement, dated November 1, 2013, as amended on June 9, 2014, November 13, 2014, June 21, 2016, December 15, 2016 and November 28, 2017, with a syndicate of banks, including Wells Fargo, as administrative agent, and its affiliate Wells Fargo Securities, LLC, as sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum credit amount of $5.0 billion, subject to a borrowing base based on the Company’s oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be redetermined, under certain circumstances, annually with an effective date of May 1st, and, under certain circumstances, semi-annually with effective dates of May 1st and November 1st. In addition, the Company and Wells Fargo may each request up to two interim redeterminations of the borrowing base during any 12-month period. As of June 30, 2018, the borrowing base was set at $2.0 billion, the Company had elected a commitment amount of $1.0 billion and the Company had $321.5 million of outstanding borrowings under the revolving credit facility and $678.5 million available for future borrowings under its revolving credit facility.

Diamondback O&G LLC is the borrower under the credit agreement. As of December 31, 2017, the credit agreement is guaranteed by the Company, Diamondback E&P LLC and Rattler Midstream LLC (formerly known as White Fang Energy LLC) and will also be guaranteed by any of the Company's future subsidiaries that are classified as restricted subsidiaries under the credit agreement. The credit agreement is also secured by substantially all of the assets of the Company, Diamondback O&G LLC and the guarantors.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Company that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate

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plus 0.5%, and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.25% to 1.25% in the case of the alternate base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the least of the maximum credit amount, the borrowing base and the elected commitment amount. 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 commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022. The 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 net debt to EBITDAX, as defined in the credit agreement	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 November 2017, allows for the issuance of unsecured debt in the form of senior or senior subordinated notes if no default would result from the incurrence of such debt after giving effect thereto and if, in connection with any such issuance, the borrowing base is reduced by 25% of the stated principal amount of each such issuance.

As of June 30, 2018 and December 31, 2017, 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

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as administrative agent, certain other lenders and the Operating Company, the Partnership’s consolidated subsidiary, as guarantor. On May 8, 2018, the Operating Company assumed all liabilities as borrower under the credit agreement and the Partnership became a guarantor of the credit agreement. On July 20, 2018, the Operating Company, the Partnership, Wells Fargo and the other lenders amended and restated the credit agreement to reflect the assumption by the Operating Company.

The credit agreement, as amended and restated, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on the Partnership's oil and natural gas reserves and other factors (the "borrowing base") of $475.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. As of June 30, 2018, the borrowing base was set at $475.0 million, and there was $350.0 million of outstanding borrowings and $125.0 million available for future borrowings under the revolving credit facility.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by the Operating Company that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. The Operating Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (i) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (ii) 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 (iii) at the maturity date of November 1, 2022. The loan is secured by substantially all of the assets of the Partnership and the Operating Company.

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $400.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

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

10. CAPITAL STOCK AND EARNINGS PER SHARE

Diamondback completed no equity offerings during the six months ended June 30, 2018 and June 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.

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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands, except per share amounts)			
Net income attributable to common stock	$219,146	$158,405	$381,958	$294,678
Weighted average common shares outstanding				
Basic weighted average common units outstanding	98,614	98,142	98,584	95,665
Effect of dilutive securities:				
Potential common shares issuable	183	212	236	260
Diluted weighted average common shares outstanding	98,797	98,354	98,820	95,925
Basic net income attributable to common stock	$2.22	$1.61	$3.87	$3.08
Diluted net income attributable to common stock	$2.22	$1.61	$3.87	$3.07

For the three months ended June 30, 2018 and 2017, there were 31,826 shares and 64,411 shares, respectively, and during the both six months ended June 30, 2018 and 2017, there were no shares 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.

11. EQUITY-BASED COMPENSATION

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
General and administrative expenses	$5,650	$6,168	$13,101	$13,231
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	2,349	1,901	4,990	4,244

Restricted Stock Units

The following table presents the Company’s restricted stock units activity under the Equity Plan during the six months ended June 30, 2018:

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	243,577	$ 90.88
Granted	81,633	$ 113.81
Vested	(115,711)	$ 86.75
Forfeited	(5,672)	$ 92.78
Unvested at June 30, 2018	203,827	$ 102.86

The aggregate fair value of restricted stock units that vested during the six months ended June 30, 2018 and 2017 was $10.0 million and $11.4 million, respectively. As of June 30, 2018, the Company’s unrecognized compensation cost related to unvested restricted stock awards and units was $15.0 million. Such cost is expected to be recognized over a weighted-average period of 1.6 years.

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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 2018, eligible employees received performance restricted stock unit awards totaling 117,423 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, 2018 to December 31, 2020 and cliff vest at December 31, 2020.

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 2018 awards.

	2018 Three-Year Performance Period
Grant-date fair value	$ 170.45
Risk-free rate	1.99 %
Company volatility	35.90 %

The following table presents the Company's performance restricted stock units activity under the Equity Plan for the six months ended June 30, 2018:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	202,326	$ 139.83
Granted	285,737	$ 130.96
Vested	(168,314)	$ 103.41
Unvested at June 30, 2018(1)	319,749	$ 151.08

(1) A maximum of 639,498 units could be awarded based upon the Company's final TSR ranking.

As of June 30, 2018, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $27.6 million. Such cost is expected to be recognized over a weighted-average period of 1.5 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.

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The following table presents the phantom unit activity under the Viper LTIP for the six months ended June 30, 2018.

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2017	105,439	$ 17.10
Granted	101,403	$ 23.18
Vested	(46,379)	$ 21.41
Unvested at June 30, 2018	160,463	$ 19.70

The aggregate fair value of phantom units that vested during the six months ended June 30, 2018 was $1.0 million. As of June 30, 2018, the unrecognized compensation cost related to unvested phantom units was $1.9 million. Such cost is expected to be recognized over a weighted-average period of 1.1 years.

12. RELATED PARTY TRANSACTIONS

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 pay any amounts during the three months and six months ended June 30, 2018 or June 30, 2017 under the Viper Advisory Services Agreement.

Lease Bonus - The Partnership
During the three months and six months ended June 30, 2018, the Company did not pay the Partnership any lease bonus payments. During the three months ended June 30, 2017, the Company paid the Partnership $0.1 million in lease bonus payments to extend the term of one lease, reflecting an average bonus of $10,000 per acre. During the six months ended June 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.

13. INCOME TAXES

The Company’s effective income tax rates were 7.8% and 1.1% for the six months ended June 30, 2018 and 2017, respectively. Total income tax expense for the six months ended June 30, 2018 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income primarily due to (i) the impact of deferred taxes recognized by the Partnership as a result of its change in tax status, (ii) current and deferred state income taxes, (iii) net income attributable to the non-controlling interest, and (iv) the impact of permanent differences between book and taxable income. The Company recorded a discrete income tax benefit of approximately $0.3 million related to equity-based compensation for the six months ended June 30, 2018 and a discrete benefit of $72.7 million related to deferred taxes on the Partnership’s investment in the Operating Company arising from the change in the Partnership’s tax status. Total income tax expense for the six months ended June 30, 2018 differed from amounts computed by applying the federal statutory rate to pre-tax income primarily due to state income taxes and the change in the valuation allowance which offset the Company's federal net deferred tax position in that period.

The Tax Cuts and Jobs Act, a historic reform of the U.S. federal income tax statutes, was enacted on December 22, 2017. As of the completion of the Company's financial statements for the year ended December 31, 2017, the Company had substantially completed its accounting for the effects of the enactment of the Tax Cuts and Jobs Act and, with respect to those items for which the Company's accounting was not complete, the Company made reasonable estimates of the effects on its deferred tax balances. At June 30, 2018, the Company has not made an adjustment to the provisional estimates recorded for the year ended December 31, 2017. The Company has considered in its estimated annual effective tax rate for 2018 the impact of the statutory changes enacted by the Tax Cuts and Jobs Act, including reasonable estimates of those provisions effective for the 2018 tax year.

As discussed further in Note 5, on March 29, 2018, the Partnership announced that the Board of Directors of its General Partner had unanimously approved a change of the Partnership's federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. The transactions undertaken in connection with the change in the Partnership's tax status were not taxable to the Company. Subsequent to the Partnership's change in tax status, the Partnership's provision for income taxes for the period ended June 30, 2018 is based on its estimated annual effective tax rate plus discrete items. As such, the Partnership's provision for income taxes is included in the Company's consolidated financial statements and to the extent applicable, in net income attributable to the non-controlling interest.

14. 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 three-way costless collars with corresponding put, short 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, a three-way collar is a combination of three options: a ceiling call, a floor put, and a short put. The counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the ceiling price to a maximum of the difference between the floor price and the short put price. The Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the ceiling price. If the settlement price is between the floor and the ceiling 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 (Cushing and Magellan East Houston) 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.

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As of June 30, 2018, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	2018		2019	
	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
Oil Swaps - WTI Cushing	4,876,000	$ 51.27	1,638,000	$ 52.78
Oil Swaps - WTI Magellan East Houston	460,000	$ 69.64	450,000	$ 68.17
Oil Swaps - BRENT	1,472,000	$ 59.69	725,000	$ 72.63
Oil Basis Swaps	2,760,000	$ (0.88)	0	$ —
Natural Gas Swaps	3,680,000	$ 3.04	0	$ —

	October 2018 - December 2018	January 2019 - June 2019		
Oil Three-Way Collars	WTI Magellan East Houston	WTI Cushing	Brent	WTI Magellan East Houston
Volume (Bbls)	276,000	1,810,000	2,000,000	270,000
Short put price (per Bbl)	$ 55.00	$45.00	$ 55.00	$ 55.00
Floor price (per Bbl)	$ 65.00	$55.00	$ 65.00	$ 65.00
Ceiling price (per Bbl)	$ 78.78	$70.23	$ 82.47	$ 76.83

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 June 30, 2018 and December 31, 2017.

	June 30, 2018	December 31, 2017
	(in thousands)	
Gross amounts of assets presented in the Consolidated Balance Sheet	$—	$ 531
Net amounts of assets presented in the Consolidated Balance Sheet	—	531
Gross amounts of liabilities presented in the Consolidated Balance Sheet	119,844	106,670
Net amounts of liabilities presented in the Consolidated Balance Sheet	$119,844	$ 106,670

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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:

	June 30, 2018	December 31, 2017
	(in thousands)	
Current assets: derivative instruments	$—	$ 531
Noncurrent assets: derivative instruments	—	—
Total assets	$—	$ 531
Current liabilities: derivative instruments	$111,330	$ 100,367
Noncurrent liabilities: derivative instruments	8,514	6,303
Total liabilities	$119,844	$ 106,670

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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Change in fair value of open non-hedge derivative instruments	$(13,667)	$28,635	$(13,705)	$68,010
Gain (loss) on settlement of non-hedge derivative instruments	(44,920)	4,685	(77,227)	3,011
Gain (loss) on derivative instruments	$(58,587)	$33,320	$(90,932)	$71,021

15. 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.

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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 and cost method investment. 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 June 30, 2018 and December 31, 2017.

	June 30, 2018	December 31, 2017
	(in thousands)	
Fixed price swaps:		
Quoted prices in active markets level 1	$20,438	$ —
Significant other observable inputs level 2	(119,844)	(106,139)
Significant unobservable inputs level 3	—	—
Total	$(99,406)	$ (106,139)

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:

	June 30, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$321,500	$321,500	$397,000	$397,000
4.750% Senior Notes due 2024	500,000	488,750	500,000	501,855
5.375% Senior Notes due 2025	800,000	800,000	500,000	515,000
Partnership revolving credit facility	350,000	350,000	93,500	93,500

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 June 30, 2018 quoted market price, a Level 1 classification in the fair value hierarchy.

16. 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.

17. SUBSEQUENT EVENTS

Recent Acquisition

On July 22, 2018, the Company entered into a definitive purchase agreement to acquire all leasehold interests and related assets of Ajax Resources, LLC which includes approximately 25,493 net leasehold acres in the Northern Midland Basin for $900.0 million in cash and approximately 2.6 million shares of the Company’s common stock,

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subject to certain adjustments. This transaction is expected to close at the end of October 2018, effective as of July 1, 2018. The cash portion of this transaction is expected to be funded through a combination of cash on hand, proceeds from the sale of assets to the Partnership (described below), borrowing under the Company's revolving credit facility and/or proceeds from one more capital markets transactions, which may include a debt offering.

Pending Drop-down Transaction
On July 27, 2018, the Company entered into a definitive agreement with the Partnership to sell to the Partnership mineral interests underlying 34,349 gross (1,696 net royalty) acres primarily in the Pecos County in the Permian Basin, approximately 80% of which are operated by the Company for $175.0 million, subject to post-closing adjustments (the “Drop-down Transaction”). The Company anticipates that the closing of the Drop-down Transaction will occur in August 2018.
Second Quarter Dividend Declaration
On August 2, 2018, the Board of Directors of the Company declared a cash dividend for the second quarter of 2018 of $0.125 per share of common stock, payable on August 27, 2018 to its stockholders of record at the close of business on August 20, 2018.
Commodity Contracts

Subsequent to June 30, 2018, the Company entered into new fixed price basis swaps and three-way costless collars. 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 (Cushing and Magellan East Houston) and Crude Oil Brent.

The following tables present the derivative contracts entered into by the Company subsequent to June 30, 2018. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
January 2019 - March 2019		
Oil Basis Swaps - WTI Cushing	180,000	$ (10.13)

Oil Three-Way Collars	WTI - Magellan East Houston October 2018 - December 2018	January 2019 - June 2019
Volume (Bbls)	184,000	362,000
Short put price (per Bbl)	$ 55.00	$ 55.00
Floor price (per Bbl)	$ 65.00	$ 65.00
Ceiling price (per Bbl)	$ 77.40	$ 76.33

The Partnership’s Amended and Restated Senior Secured Revolving Credit Agreement

On July 20, 2018, the Operating Company, as borrower, and the Partnership, as guarantor, entered into an Amended and Restated Senior Secured Revolving Credit Agreement among Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amended and restated the Senior Secured Revolving Credit Agreement, dated as of July 8, 2014, as amended, to incorporate the terms of an assignment and assumption dated May 8, 2018 by and between the Partnership and the Operating Company, whereby the Partnership assigned its liabilities and rights as borrower under the Senior Secured Revolving Credit Agreement to the Operating Company, with the Operating Company becoming the borrower and assuming all liabilities of the borrower thereunder and the Partnership becoming a guarantor under the Senior Secured Revolving Credit Agreement. All other material terms of the Senior Secured Revolving Credit Agreement remained unchanged and are in effect as of the date of the Amended and Restated Senior Secured Revolving Credit Agreement.

The Partnership's July 2018 Equity Offering

In July 2018, the Partnership completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 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 $305.3 million, after deducting underwriting discounts and commissions and estimated offering expenses. The Partnership used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under the revolving credit facility.

Lease Bonus Payments

Subsequent to June 30, 2018, the Company paid the Partnership $2.0 million related to two new leases, reflecting an average bonus of $10,000 per acre.

18. GUARANTOR FINANCIAL STATEMENTS

As of June 30, 2018, 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, as supplemented. In connection with the issuance of the 2024 Senior Notes and the 2025 Senior Notes (including the New 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 18 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.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
June 30, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$65,218	$15,823	$32,886	$—	$113,927
Accounts receivable	—	227,807	31,083	—	258,890
Accounts receivable - related party	—	—	8,137	(8,137)	—
Intercompany receivable	2,862,029	787,088	—	(3,649,117)	—
Inventories	—	13,264	—	—	13,264
Other current assets	441	6,530	295	—	7,266
Total current assets	2,927,688	1,050,512	72,401	(3,657,254)	393,347
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	8,956,243	1,359,596	(414)	10,315,425
Midstream assets	—	343,387	—	—	343,387
Other property, equipment and land	—	84,471	1,001	—	85,472
Accumulated depletion, depreciation, amortization and impairment	—	(2,183,228)	(214,252)	(3,760)	(2,401,240)
Net property and equipment	—	7,200,873	1,146,345	(4,174)	8,343,044
Investment in subsidiaries	4,262,879	1,284	1,000	(4,265,163)	—
Deferred income taxes	—	—	72,049	—	72,049
Investment in real estate	—	108,564	—	—	108,564
Other assets	—	11,831	25,560	—	37,391
Total assets	$7,190,567	$8,373,064	$1,317,355	$(7,926,591)	$8,954,395
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$11	$73,954	$9	$—	$73,974
Intercompany payable	37,962	3,619,292	—	(3,657,254)	—
Other current liabilities	8,095	641,960	3,048	—	653,103
Total current liabilities	46,068	4,335,206	3,057	(3,657,254)	727,077
Long-term debt	1,295,574	321,500	350,000	—	1,967,074
Derivative instruments	—	8,514	—	—	8,514
Asset retirement obligations	—	21,780	—	—	21,780
Deferred income taxes	217,476	—	—	—	217,476
Other long term liabilities	—	7	—	—	7
Total liabilities	1,559,118	4,687,007	353,057	(3,657,254)	2,941,928
Commitments and contingencies					
Stockholders' equity	5,631,449	3,686,057	389,797	(4,075,854)	5,631,449
Non-controlling interest	—	—	574,501	(193,483)	381,018
Total equity	5,631,449	3,686,057	964,298	(4,269,337)	6,012,467
Total liabilities and equity	$7,190,567	$8,373,064	$1,317,355	$(7,926,591)	$8,954,395

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
December 31, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$54,074	$34,175	$24,197	$—	$112,446
Accounts receivable	—	205,859	25,754	—	231,613
Accounts receivable - related party	—	—	5,142	(5,142)	—
Intercompany receivable	2,624,810	2,267,308	—	(4,892,118)	—
Inventories	—	9,108	—	—	9,108
Other current assets	618	4,461	355	—	5,434
Total current assets	2,679,502	2,520,911	55,448	(4,897,260)	358,601
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	8,129,211	1,103,897	(414)	9,232,694
Midstream assets	—	191,519	—	—	191,519
Other property, equipment and land	—	80,776	—	—	80,776
Accumulated depletion, depreciation, amortization and impairment	—	(1,976,248)	(189,466)	4,342	(2,161,372)
Net property and equipment	—	6,425,258	914,431	3,928	7,343,617
Funds held in escrow	—	—	6,304	—	6,304
Investment in subsidiaries	3,809,557	—	—	(3,809,557)	—
Other assets	—	25,609	36,854	—	62,463
Total assets	$6,489,059	$8,971,778	$1,013,037	$(8,702,889)	$7,770,985
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$1	$91,629	$2,960	$—	$94,590
Intercompany payable	132,067	4,765,193	—	(4,897,260)	—
Other current liabilities	7,236	472,933	2,669	—	482,838
Total current liabilities	139,304	5,329,755	5,629	(4,897,260)	577,428
Long-term debt	986,847	397,000	93,500	—	1,477,347
Derivative instruments	—	6,303	—	—	6,303
Asset retirement obligations	—	20,122	—	—	20,122
Deferred income taxes	108,048	—	—	—	108,048
Total liabilities	1,234,199	5,753,180	99,129	(4,897,260)	2,189,248
Commitments and contingencies					
Stockholders’ equity	5,254,860	3,218,598	913,908	(4,132,506)	5,254,860
Non-controlling interest	—	—	—	326,877	326,877
Total equity	5,254,860	3,218,598	913,908	(3,805,629)	5,581,737
Total liabilities and equity	$6,489,059	$8,971,778	$1,013,037	$(8,702,889)	$7,770,985

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Three Months Ended June 30, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$ 394,552	$ —	$ 65,885	$ 460,437
Natural gas sales	—	8,714	—	2,651	11,365
Natural gas liquid sales	—	37,251	—	5,884	43,135
Royalty income	—	—	74,420	(74,420)	—
Lease bonus income	—	—	928	—	928
Midstream services	—	7,983	—	—	7,983
Other operating income	—	2,367	58	—	2,425
Total revenues	—	450,867	75,406	—	526,273
Costs and expenses:					
Lease operating expenses	—	42,647	—	—	42,647
Production and ad valorem taxes	—	27,335	4,867	—	32,202
Gathering and transportation	—	6,670	143	—	6,813
Midstream services	—	17,601	—	—	17,601
Depreciation, depletion and amortization	—	111,980	13,260	4,627	129,867
General and administrative expenses	6,539	6,395	2,210	(615)	14,529
Asset retirement obligation accretion	—	365	—	—	365
Other operating expense	—	946	—	—	946
Total costs and expenses	6,539	213,939	20,480	4,012	244,970
Income (loss) from operations	(6,539)	236,928	54,926	(4,012)	281,303
Other income (expense)					
Interest expense, net	(10,145)	(3,699)	(3,252)	—	(17,096)
Other income (expense), net	211	84,429	447	(615)	84,472
Loss on derivative instruments, net	—	(58,587)	—	—	(58,587)
Gain on revaluation of investment	—	—	4,465	—	4,465
Total other income (expense), net	(9,934)	22,143	1,660	(615)	13,254
Income (loss) before income taxes	(16,473)	259,071	56,586	(4,627)	294,557
Provision for (benefit from) income taxes	65,271	—	(71,878)	—	(6,607)
Net income (loss)	(81,744)	259,071	128,464	(4,627)	301,164
Net income attributable to non-controlling interest	—	—	29,060	52,958	82,018
Net income (loss) attributable to Diamondback Energy, Inc.	$(81,744)	$ 259,071	$ 99,404	$ (57,585)	$ 219,146

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

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

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$ 206,113	$ —	$ 31,771	$ 237,884
Natural gas sales	—	10,739	—	1,954	12,693
Natural gas liquid sales	—	14,649	—	2,208	16,857
Royalty income	—	—	35,933	(35,933)	—
Lease bonus income	—	—	689	(106)	583
Midstream services	—	1,417	—	—	1,417
Total revenues	—	232,918	36,622	(106)	269,434
Costs and expenses:					
Lease operating expenses	—	28,989	—	—	28,989
Production and ad valorem taxes	—	13,106	2,773	—	15,879
Gathering and transportation	—	2,871	144	—	3,015
Midstream services	—	1,828	—	—	1,828
Depreciation, depletion and amortization	—	65,091	9,672	410	75,173
General and administrative expenses	6,432	4,521	1,554	(615)	11,892
Asset retirement obligation accretion	—	350	—	—	350
Total costs and expenses	6,432	116,756	14,143	(205)	137,126
Income (loss) from operations	(6,432)	116,162	22,479	99	132,308
Other income (expense)					
Interest expense, net	(6,325)	(1,277)	(643)	—	(8,245)
Other income (expense), net	—	8,626	313	(615)	8,324
Gain on derivative instruments, net	—	33,320	—	—	33,320
Total other income (expense), net	(6,325)	40,669	(330)	(615)	33,399
Income (loss) before income taxes	(12,757)	156,831	22,149	(516)	165,707
Provision for income taxes	1,579	—	—	—	1,579
Net income (loss)	(14,336)	156,831	22,149	(516)	164,128
Net income attributable to non-controlling interest	—	—	—	5,723	5,723
Net income (loss) attributable to Diamondback Energy, Inc.	$(14,336)	$ 156,831	$ 22,149	$ (6,239)	$ 158,405

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Six Months Ended June 30, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	—	758,133	—	121,572	879,705
Natural gas sales	—	20,514	—	5,229	25,743
Natural gas liquid sales	—	66,236	—	10,012	76,248
Royalty income	—	—	136,813	(136,813)	—
Lease bonus income	—	—	928	—	928
Midstream services	—	19,378	—	—	19,378
Other operating income	—	4,358	108	—	4,466
Total revenues	—	868,619	137,849	—	1,006,468
Costs and expenses:					
Lease operating expenses	—	79,992	—	—	79,992
Production and ad valorem taxes	—	50,400	9,106	—	59,506
Gathering and transportation	—	10,690	408	—	11,098
Midstream services	—	28,790	—	—	28,790
Depreciation, depletion and amortization	—	212,196	24,785	8,102	245,083
General and administrative expenses	14,029	13,134	4,921	(1,230)	30,854
Asset retirement obligation accretion	—	720	—	—	720
Other operating expense	—	1,476	—	—	1,476
Total costs and expenses	14,029	397,398	39,220	6,872	457,519
Income (loss) from operations	(14,029)	471,221	98,629	(6,872)	548,949
Other income (expense)					
Interest expense, net	(19,077)	(6,370)	(5,350)	—	(30,797)
Other income (expense), net	334	87,265	839	(1,230)	87,208
Loss on derivative instruments, net	—	(90,932)	—	—	(90,932)
Gain on revaluation of investment	—	—	5,364	—	5,364
Total other income (expense), net	(18,743)	(10,037)	853	(1,230)	(29,157)
Income (loss) before income taxes	(32,772)	461,184	99,482	(8,102)	519,792
Provision for (benefit from) income taxes	112,352	—	(71,878)	—	40,474
Net income (loss)	(145,124)	461,184	171,360	(8,102)	479,318
Net income attributable to non-controlling interest	—	—	29,060	68,300	97,360
Net income (loss) attributable to Diamondback Energy, Inc.	(145,124)	461,184	142,300	(76,402)	381,958

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Six Months Ended June 30, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$—	$ 384,343	$ —	$ 60,615	$ 444,958
Natural gas sales	—	19,314	—	3,301	22,615
Natural gas liquid sales	—	28,292	—	4,067	32,359
Royalty income	—	—	67,983	(67,983)	—
Lease bonus income	—	—	2,291	(106)	2,185
Midstream services	—	2,547	—	—	2,547
Total revenues	—	434,496	70,274	(106)	504,664
Costs and expenses:					
Lease operating expenses	—	55,615	—	—	55,615
Production and ad valorem taxes	—	26,761	4,843	—	31,604
Gathering and transportation	—	5,347	287	—	5,634
Midstream services	—	2,682	—	—	2,682
Depreciation, depletion and amortization	—	115,982	17,519	601	134,102
General and administrative expenses	13,540	9,630	3,696	(1,230)	25,636
Asset retirement obligation accretion	—	673	—	—	673
Total costs and expenses	13,540	216,690	26,345	(629)	255,946
Income (loss) from operations	(13,540)	217,806	43,929	523	248,718
Other income (expense)					
Interest expense, net	(17,133)	(2,082)	(1,255)	—	(20,470)
Other income (expense), net	1,092	9,480	127	(1,230)	9,469
Gain on derivative instruments, net	—	71,021	—	—	71,021
Total other income (expense), net	(16,041)	78,419	(1,128)	(1,230)	60,020
Income (loss) before income taxes	(29,581)	296,225	42,801	(707)	308,738
Provision for income taxes	3,536	—	—	—	3,536
Net income (loss)	(33,117)	296,225	42,801	(707)	305,202
Net income attributable to non-controlling interest	—	—	—	10,524	10,524
Net income (loss) attributable to Diamondback Energy, Inc.	$(33,117)	$ 296,225	$ 42,801	$ (11,231)	$ 294,678

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Six Months Ended June 30, 2018
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$(21,030)	$ 673,171	$ 112,212	$ —	$ 764,353
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(650,058)	—	—	(650,058)
Additions to midstream assets	—	(94,503)	—	—	(94,503)
Purchase of other property, equipment and land	—	(3,978)	—	—	(3,978)
Acquisition of leasehold interests	—	(101,216)	—	—	(101,216)
Acquisition of mineral interests	—	(46)	(253,056)	—	(253,102)
Proceeds from sale of assets	—	3,313	566	—	3,879
Funds held in escrow	—	10,989	—	—	10,989
Equity investments	—	(125)	—	—	(125)
Intercompany transfers	(22,310)	22,310	—	—	—
Investment in real estate	—	(110,480)	—	—	(110,480)
Net cash used in investing activities	(22,310)	(923,794)	(252,490)	—	(1,198,594)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	312,500	256,500	—	569,000
Repayment under credit facility	—	(388,000)	—	—	(388,000)
Proceeds from senior notes	312,000	—	—	—	312,000
Debt issuance costs	(3,706)	(229)	(440)	—	(4,375)
Public offering costs	(254)	—	(2,034)	—	(2,288)
Contributions to subsidiaries	(1,000)	—	(1,000)	2,000	—
Contributions by members	—	—	2,000	(2,000)	—
Distributions from subsidiary	68,771	—	—	(68,771)	—
Dividends to stockholders	(12,327)	—	—	—	(12,327)
Distributions to non-controlling interest	—	—	(107,059)	68,771	(38,288)
Intercompany transfers	(309,000)	308,000	1,000	—	—
Net cash provided by financing activities	54,484	232,271	148,967	—	435,722
Net increase (decrease) in cash and cash equivalents	11,144	(18,352)	8,689	—	1,481
Cash and cash equivalents at beginning of period	54,074	34,175	24,197	—	112,446
Cash and cash equivalents at end of period	$65,218	$ 15,823	$ 32,886	$ —	$ 113,927

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Six Months Ended June 30, 2017
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$(25,139)	$358,123	$61,447	$—	$394,431
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(291,767)	—	—	(291,767)
Purchase of other property, equipment and land	—	(13,825)	—	—	(13,825)
Acquisition of leasehold interests	—	(1,860,980)	—	—	(1,860,980)
Acquisition of mineral interests	—	—	(122,679)	—	(122,679)
Acquisition of midstream assets	—	(50,279)	—	—	(50,279)
Additions to midstream assets	—	(4,444)	—	—	(4,444)
Proceeds from sale of assets	—	1,295	—	—	1,295
Funds held in escrow	—	121,391	—	—	121,391
Equity investments	—	(188)	—	—	(188)
Intercompany transfers	(1,657,407)	1,657,407	—	—	—
Net cash used in investing activities	(1,657,407)	(441,390)	(122,679)	—	(2,221,476)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	162,000	104,000	—	266,000
Repayment under credit facility	—	(78,000)	(143,000)	—	(221,000)
Debt issuance costs	(635)	(790)	(180)	—	(1,605)
Public offering costs	(79)	—	(217)	—	(296)
Proceeds from public offerings	—	—	147,725	—	147,725
Distributions from subsidiary	40,572	—	—	(40,572)	—
Exercise of stock options	358	—	—	—	358
Distributions to non-controlling interest	—	—	(54,695)	40,572	(14,123)
Net cash provided by financing activities	40,216	83,210	53,633	—	177,059
Net decrease in cash and cash equivalents	(1,642,330)	(57)	(7,599)	—	(1,649,986)
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	$896	$14,078	$1,614	$—	$16,588

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, 2017. 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Oil (MBbls)	73 %	75 %	73 %	75 %
Natural gas (MMcf)	12 %	12 %	12 %	11 %
Natural gas liquids (MBbls)	15 %	13 %	15 %	14 %
	100 %	100 %	100 %	100 %

As of June 30, 2018, we had approximately 204,254 net acres, which consisted of approximately 99,913 net acres in the Northern Midland Basin and approximately 104,341 net acres in the Southern Delaware Basin. As of December 31, 2017, we had an estimated 3,800 gross horizontal locations that we believe to be economic at $60 per Bbl West Texas Intermediate, or WTI.

In the second quarter of 2018, we again demonstrated our operational focus on achieving best-in-class execution, low-cost operations and a conservative balance sheet as we continued to execute on our growth plan while maintaining cash operating margins in excess of 80% on a per BOE basis. In doing so, we achieved another quarter of robust production growth within cash flow, which has allowed us to maintain a low leverage ratio, while generating what we believe to be a peer leading return on average capital employed. During the second quarter of 2018, we operated 11 drilling rigs and five dedicated frac spreads, and plan to add our 12th and 13th operating rigs to development during the third quarter of 2018.

2018 Highlights

Pending Drop-down Transaction

On July 27, 2018, we entered into a definitive agreement with Viper Energy Partners LP, our publicly-held subsidiary, which we refer to as Viper, to sell to Viper mineral interests underlying 34,349 gross (1,696 net royalty) acres primarily in the Pecos County in the Permian Basin, approximately 80% of which are operated by us, for $175.0 million, subject to post-closing adjustments, which we refer to as the Drop-down Transaction. The Drop-down Transaction was approved by the respective boards of directors of the Company and the General Partner of the Partnership. We anticipate that the closing of the Drop-down Transaction will occur in August 2018.

Pending Acquisition of Assets from Ajax Resources, LLC
In July 2018, we entered into a definitive purchase agreement to acquire 25,493 net leasehold acres (89% of which is held by production and 99% of which is operated, with an average 99% working interest and 23% average royalty burden), from Ajax Resources LLC, or Ajax, including approximately 21,000 net acres in Northwest Martin and Andrews counties, with current net production of approximately 12,100 Boe per day (88% oil) as of August 8, 2018, for $900.0 million in cash and approximately 2.6 million shares of our common stock, subject to certain adjustments, which we refer to as the Pending Ajax Acquisition. The acreage subject to the Pending Ajax Acquisition has approximately 362 net identified potential horizontal locations, with an average lateral length of over 9,500 feet. The acquisition also includes midstream assets consisting of 40 Mb/d of saltwater disposal, or SWD, gathering lines and disposal capacity, 45 Mb/d of fresh water storage capacity, 20 miles of fresh water and SWD gathering lines and over 700 surface acres. We expect to fund the cash portion of the consideration for the Pending Ajax Acquisition through a combination of cash on hand, proceeds from the pending Drop-down Transaction discussed above, borrowings under our revolving credit facility and/or proceeds from one or more capital markets transactions, which may include a debt offering. The Pending Ajax Acquisition is expected to close at the end of October 2018, effective as of July 1, 2018; however, the closing of the Pending Ajax Acquisition is subject to continued diligence and closing conditions. Upon completion, the Pending Ajax Acquisition is expected to bring our total leasehold interests to approximately 230,000 net surface areas in the Permian Basin and increase our net identified potential horizontal drilling locations to approximately 680 in this area.
Transportation Contracts
In July 2018, we executed agreements to secure firm oil transportation out of the basin at fixed discounts to Gulf Coast pricing beginning with the third quarter of 2018 and term sales agreements to cover the remainder of expected production. We also executed an agreement for option to acquire up to 10% equity interest in the EPIC Crude Oil Pipeline project with a volume commitment from 50,000 BOE/d to 100,000 BOE/d.

Second Quarter Dividend Declaration

On August 2, 2018, our board of directors declared a cash dividend for the second quarter of 2018 of $0.125 per share of common stock, payable on August 27, 2018 to our stockholders of record at the close of business on August 20, 2018.

Viper’s July 2018 Equity Offering

In July 2018, Viper completed an underwritten public offering of 10,080,000 common units, which included 1,080,000 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 $305.3 million, after deducting underwriting discounts and commissions and estimated offering expenses. Viper used the net proceeds to purchase units of the Operating Company. The Operating Company in turn used the net proceeds to repay a portion of the $361.5 million then outstanding borrowings under the revolving credit facility.

Operational Update

During the three months ended June 30, 2018, we drilled 53 gross (50 net) operated horizontal wells, of which 19 gross (18 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 50 gross (46 net) operated horizontal wells into production, of which 34 gross (29 net) wells were in the Midland Basin and the remaining wells were in the Delaware Basin.

During the second quarter of 2018, we operated 11 drilling rigs and five dedicated frac spreads, and plan to add our 12th and 13th operating rigs to development during the third quarter of 2018. We plan to operate six to seven of these drilling rigs in the Midland Basin targeting horizontal development of the Wolfcamp and Spraberry formations, while the remainder of the drilling 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 between six and seven drilling rigs across our Northern Midland Basin acreage for the remainder of 2018.

In the Delaware Basin, we are currently operating five drilling rigs, with plans to operate between five and six drilling rigs for the remainder of 2018. Our 2018 development plan is primarily focused on long-lateral Wolfcamp A wells in Pecos, Reeves and Ward counties. Additionally, in the second half of 2018 we expect to conduct further appraisal of the Second Bone Spring interval in Pecos county.

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 additional pricing increases after a prolonged period of declining costs in 2015 and 2016. To combat rising service costs, we have taken proactive measures such as securing frac sand supply for future well completions and will continue to seek opportunities to control and de-bundle additional costs where possible. We believe that our 2018 drilling and completion budget covers potential increases in our service costs during the year.

Recapitalization, Tax Status Election and Related Transactions by Viper

In March 2018, Viper announced that the Board of Directors of its general partner had unanimously approved a change of Viper's federal income tax status from that of a pass-through partnership to that of a taxable entity via a "check the box" election. In connection with making this election, on May 9, 2018 Viper (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of Viper Energy Partners LLC, or the Operating Company, (iii) amended and restated its existing registration rights agreement with us and (iv) entered into an exchange agreement with us, Viper's general partner, or the General Partner, and the Operating Company. Simultaneously with the effectiveness of these agreements, we delivered and assigned to Viper the 73,150,000 common units we owned in exchange for (i) 73,150,000 of Viper's newly-issued Class B units and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018, or the Recapitalization Agreement. Immediately following that exchange, Viper continued to be the managing member of the Operating Company, with sole control of its operations, and owned approximately 36% of the outstanding units issued by the Operating Company, and we owned the remaining approximately 64% of the outstanding units issued by the Operating Company. The Operating Company units and Viper's Class B units owned by us are exchangeable from time to time for Viper's common units (that is, one Operating Company unit and one Viper Class B unit, together, will be exchangeable for one Viper common unit).

On May 10, 2018, the change in Viper's income tax status became effective. On that date, pursuant to the terms of the Recapitalization Agreement, (i) the General Partner made a cash capital contribution of $1.0 million to Viper in respect of its general partner interest and (ii) we made a cash capital contribution of $1.0 million to Viper in respect of the Class B units. We, as the holder of the Class B units, and the General Partner, as the holder of the general partner interest, are entitled to receive an 8% annual distribution on the outstanding amount of these capital contributions, payable quarterly, as a return on this invested capital. On May 10, 2018, we also exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of Viper and a cash amount of $10,000 representing a proportionate return of the $1.0 million invested capital in respect of the Class B units. The General Partner continues to serve as Viper's general partner and we continue to control Viper. After the effectiveness of the tax status election and the completion of related transactions, Viper's minerals business continues to be conducted through the Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. This structure is anticipated to provide significant benefits to Viper's business, including operational effectiveness, acquisition and disposition transactional planning flexibility and income tax efficiency. For additional information regarding the tax status election and related transactions, please refer to Viper's Definitive Information Statement on Schedule 14C filed with the SEC on April 17, 2018 and Viper's Current Report on Form 8-K filed with the SEC on May 15, 2018.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Oil (Bbls)/d	82,180	57,543	78,886	51,903
Natural Gas (Mcf)/d	80,960	54,273	76,867	47,635
Natural Gas Liquids (Bbls)/d	16,919	10,388	15,929	9,493
Total average production per day (BOE)	112,592	76,977	107,627	69,336

Our average daily production for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017 increased 35,615 BOE/d, or 46.3%.

Sources of Our Revenues

Our main sources of revenues are 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenues				
Oil sales	89 %	89 %	90 %	89 %
Natural gas sales	2 %	5 %	3 %	5 %
Natural gas liquid sales	9 %	6 %	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 or natural gas liquids prices. Oil, natural gas and natural gas liquids prices have historically been volatile. During 2017, WTI posted prices ranged from $42.48 to $60.46 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.44 to $3.71 per MMBtu. During the first six months of 2018, WTI posted prices ranged from $59.20 to $77.41 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.49 to $6.24 per MMBtu. On June 29, 2018, the WTI posted price for crude oil was $74.13 per Bbl and the Henry Hub spot market price of natural gas was $2.96 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 June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands, except Bbl, Mcf and BOE amounts)			
Revenues:				
Oil, natural gas and natural gas liquids	$514,937	$267,434	$981,696	$499,932
Lease bonus	928	583	928	2,185
Midstream services	7,983	1,417	19,378	2,547
Other operating income	2,425	—	4,466	—
Total revenues	526,273	269,434	1,006,468	504,664
Operating expenses:				
Lease operating expenses	42,647	28,989	79,992	55,615
Production and ad valorem taxes	32,202	15,879	59,506	31,604
Gathering and transportation	6,813	3,015	11,098	5,634
Midstream services	17,601	1,828	28,790	2,682
Depreciation, depletion and amortization	129,867	75,173	245,083	134,102
General and administrative expenses	14,529	11,892	30,854	25,636
Asset retirement obligation accretion	365	350	720	673
Other operating expense	946	—	1,476	—
Total expenses	244,970	137,126	457,519	255,946
Income from operations	281,303	132,308	548,949	248,718
Interest expense, net	(17,096)	(8,245)	(30,797)	(20,470)
Other income, net	84,472	8,324	87,208	9,469
Gain (loss) on derivative instruments, net	(58,587)	33,320	(90,932)	71,021
Gain on revaluation of investment	4,465	—	5,364	—
Total other income (expense), net	13,254	33,399	(29,157)	60,020
Income before income taxes	294,557	165,707	519,792	308,738
Provision for (benefit from) income taxes	(6,607)	1,579	40,474	3,536
Net income	301,164	164,128	479,318	305,202
Net income attributable to non-controlling interest	82,018	5,723	97,360	10,524
Net income attributable to Diamondback Energy, Inc.	$219,146	$158,405	$381,958	$294,678

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
	(in thousands)			
Production Data:				
Oil (MBbls)	7,478	5,236	14,278	9,395
Natural gas (MMcf)	7,367	4,939	13,913	8,622
Natural gas liquids (MBbls)	1,540	945	2,883	1,718
Combined volumes (MBOE)	10,246	7,005	19,480	12,550
Daily combined volumes (BOE/d)	112,592	76,977	107,627	69,336
Average Prices:				
Oil (per Bbl)	$61.57	$45.43	$61.61	$47.36
Natural gas (per Mcf)	1.54	2.57	1.85	2.62
Natural gas liquids (per Bbl)	28.02	17.83	26.45	18.83
Combined (per BOE)	50.26	38.18	50.39	39.84
Oil, hedged ($ per Bbl)(1)	55.53	46.32	56.15	47.68
Natural gas, hedged ($ per MMbtu)(1)	1.57	3.52	1.91	2.97
Average price, hedged ($ per BOE)(1)	45.87	38.85	46.43	40.08
Average Costs per BOE:				
Lease operating expense	$4.16	$4.14	$4.11	$4.43
Production and ad valorem taxes	3.14	2.27	3.05	2.52
Gathering and transportation expense	0.66	0.43	0.57	0.45
General and administrative - cash component	0.87	0.82	0.91	0.99
Total operating expense - cash	$8.83	$7.66	$8.64	$8.39
General and administrative - non-cash component	$0.55	$0.88	$0.67	$1.05
Depreciation, depletion and amortization	12.68	10.73	12.58	10.69
Interest expense, net	1.67	1.18	1.58	1.63
Total expenses	$14.90	$12.79	$14.83	$13.37
Average realized oil price ($/Bbl)	$61.57	$45.43	$61.61	$47.36
Average NYMEX ($/Bbl)	68.07	47.88	65.55	49.66
Differential to NYMEX	(6.50)	(2.45)	(3.94)	(2.30)
Average realized oil price to NYMEX	90%	95%	94%	95%
Average realized natural gas price ($/Mcf)	$1.54	$2.57	$1.85	$2.62
Average NYMEX ($/Mcf)	2.85	3.35	2.96	3.04
Differential to NYMEX	(1.31)	(0.78)	(1.11)	(0.42)
Average realized natural gas price to NYMEX	54%	77%	63%	86%
Average realized natural gas liquids price ($/Bbl)	$28.02	$17.83	$26.45	$18.83
Average NYMEX oil price ($/Bbl)	68.07	47.88	65.55	49.66
Average realized natural gas liquids price to NYMEX oil price	41%	37%	40%	38%

(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 June 30, 2018 and 2017

Oil, Natural Gas and Natural Gas Liquids Revenues. Our oil, natural gas and natural gas liquids revenues increased by approximately $247.5 million, or 93%, to $514.9 million for the three months ended June 30, 2018 from $267.4 million for the three months ended June 30, 2017. Our revenues are a function of oil, natural gas and natural gas liquids production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 35,615 BOE/d to 112,592 BOE/d during the three months ended June 30, 2018 from 76,977 BOE/d during the three months ended June 30, 2017. The total increase in revenue of approximately $247.5 million is largely attributable to higher oil, natural gas and natural gas liquids production volumes and higher average sales prices for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 2,241,904 Bbls of oil, 2,428,557 Mcf of natural gas and 594,310 Bbls of natural gas liquids for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017.

The net dollar effect of the increases in prices of approximately $128.8 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas and natural gas liquids) and the net dollar effect of the increase in production of approximately $118.7 million (calculated as the increase in period-to-period volumes for oil, natural gas and natural gas liquids 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	$ 16.14	7,478	$ 120,709
Natural gas	(1.03)	7,367	(7,588)
Natural gas liquids	10.19	1,540	15,689
Total revenues due to change in price			$ 128,810

	Change in production volumes(1)	Prior period Average Prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	2,242	$ 45.43	$ 101,854
Natural gas	2,429	2.57	6,241
Natural gas liquids	594	17.83	10,598
Total revenues due to change in production volumes			118,693
Total change in revenues			$ 247,503

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

Lease Bonus Revenue. Lease bonus income increased by $0.3 million for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017. Lease bonus revenue was $0.9 million for the three months ended June 30, 2018 attributable to lease bonus payments to extend the term of two leases, reflecting an average bonus of $6,111 per acre. Lease bonus revenue was $0.6 million for the three months ended June 30, 2017 attributable to lease bonus payments to extend the term of two leases, reflecting an average bonus of $6,000 per acre.

Midstream Services Revenue. Midstream services revenue was $8.0 million for the three months ended June 30, 2018, an increase of $6.6 million as compared to $1.4 million for the three months ended June 30, 2017. We began generating midstream services revenue during the first quarter of 2017 and, prior to that period, had no midstream services revenue. 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 $42.6 million ($4.16 per BOE) for the three months ended June 30, 2018 as compared to $29.0 million ($4.14 per BOE) for the three months ended June 30, 2017. The increase in lease operating expense was a result of nonrecurring charges due to work overs.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $32.2 million for the three months ended June 30, 2018, an increase of $16.3 million, or 103%, from $15.9 million for the three months ended June 30, 2017. 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 June 30, 2018, our production and ad valorem taxes per BOE increased by $0.87 as compared to the three months ended June 30, 2017, primarily due to increased commodity prices and production volumes.

Midstream Services Expense. Midstream services expense was $17.6 million for the three months ended June 30, 2018, an increase of $15.8 million as compared to $1.8 million for the three months ended June 30, 2017. Prior to the first quarter of 2017, we had no midstream services expense. 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 $54.7 million, or 73%, to $129.9 million for the three months ended June 30, 2018 from $75.2 million for the three months ended June 30, 2017.

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

	Three Months Ended June 30,	
	2018	2017
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$123,382	$73,808
Depreciation of midstream assets	4,070	996
Depreciation of other property and equipment	2,415	369
Depreciation, depletion and amortization expense	$129,867	$75,173
Oil and natural gas properties depreciation, depletion and amortization per BOE	$12.04	$10.73

The increase in depletion of proved oil and natural gas properties of $49.6 million for the three months ended June 30, 2018 as compared to the three months ended June 30, 2017 resulted primarily from higher production levels and an increase in net book value on new reserves added.

General and Administrative Expenses. General and administrative expenses increased $2.6 million from $11.9 million for the three months ended June 30, 2017 to $14.5 million for the three months ended June 30, 2018. The increase was primarily due to an increase in salaries and benefits.

Net Interest Expense. Net interest expense for the three months ended June 30, 2018 was $17.1 million as compared to $8.2 million for the three months ended June 30, 2017, an increase of $8.9 million. This increase was due to a higher interest rate and increased borrowings during the three months ended June 30, 2018 as compared to the three months ended June 30, 2017.

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 June 30, 2018, we had a cash loss on settlement of derivative instruments of $44.9 million as compared to a cash gain on settlement of derivative instruments of $4.7 million for the three months ended June 30, 2017. For the three months ended June 30, 2018, we had a negative change in the fair value of open derivative instruments of $13.7 million as compared to a positive change of $28.6 million for the three months ended June 30, 2017.

Provision for (Benefit From) Income Taxes. We recorded an income tax benefit of $6.6 million for the three months ended June 30, 2018 as compared to an income tax provision of $1.6 million for the three months ended June 30, 2017. The change in our income tax provision was primarily due to the discrete deferred tax benefit related to

Viper's change in tax status for the three months ended June 30, 2018, and the change in the valuation allowance for the three months ended June 30, 2017.

Comparison of the Six Months Ended June 30, 2018 and 2017

Oil, Natural Gas and Natural Gas Liquids Revenues. Our oil, natural gas and natural gas liquids revenues increased by approximately $481.8 million, or 96%, to $981.7 million for the six months ended June 30, 2018 from $499.9 million for the six months ended June 30, 2017. Our revenues are a function of oil, natural gas and natural gas liquids production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 38,291 BOE/d to 107,627 BOE/d during the six months ended June 30, 2018 from 69,336 BOE/d during the six months ended June 30, 2017. The total increase in revenue of approximately $481.8 million is largely attributable to higher oil, natural gas and natural gas liquids production volumes and higher average sales prices for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 4,883,907 Bbls of oil, 5,290,993 Mcf of natural gas and 1,164,933 Bbls of natural gas liquids for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017.

The net dollar effect of the increases in prices of approximately $214.7 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas and natural gas liquids) and the net dollar effect of the increase in production of approximately $267.1 million (calculated as the increase in period-to-period volumes for oil, natural gas and natural gas liquids 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	$ 14.25	14,278	$ 203,420
Natural gas	(0.77)	13,913	(10,713)
Natural gas liquids	7.62	2,883	21,970
Total revenues due to change in price			$ 214,677

	Change in production volumes[1]	Prior period Average Prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	4,884	$ 47.36	$ 231,271
Natural gas	5,291	2.62	21,938
Natural gas liquids	1,165	18.83	13,878
Total revenues due to change in production volumes			267,087
Total change in revenues			$ 481,764

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

Lease Bonus Revenue. Lease bonus income decreased by $1.3 million for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017. Lease bonus revenue was $0.9 million for the six months ended June 30, 2018 attributable to lease bonus payments to extend the term of two leases, reflecting an average bonus of $6,111 per acre. Lease bonus revenue was $2.2 million for the six months ended June 30, 2017 attributable to lease bonus payments to extend the term of three leases, reflecting an average bonus of $2,963 per acre.

Midstream Services Revenue. Midstream services revenue was $19.4 million for the six months ended June 30, 2018, an increase of $16.8 million as compared to $2.5 million for the six months ended June 30, 2017. We began generating midstream services revenue during the first quarter of 2017 and, prior to that period, had no midstream services revenue. 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 $80.0 million ($4.11 per BOE) for the six months ended June 30, 2018 as compared to $55.6 million ($4.43 per BOE) for the six months ended June 30, 2017. The increase in lease operating expense was a result of nonrecurring charges due to work overs. The decrease in lease operating expense per BOE was a result of lease operating expenses increasing at a lower percentage than the increase in production volumes.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $59.5 million for the six months ended June 30, 2018, an increase of $27.9 million, or 88%, from $31.6 million for the six months ended June 30, 2017. 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 six months ended June 30, 2018, our production and ad valorem taxes per BOE increased by $0.53 as compared to the six months ended June 30, 2017, primarily due to increased commodity prices and production volumes.

Midstream Services Expense. Midstream services expense was $28.8 million for the six months ended June 30, 2018, an increase of $26.1 million as compared to $2.7 million for the six months ended June 30, 2017. Prior to the first quarter of 2017, we had no midstream services expense. 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 $111.0 million, or 83%, to $245.1 million for the six months ended June 30, 2018 from $134.1 million for the six months ended June 30, 2017.

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

	Six Months Ended June 30,	
	2018	2017
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$232,369	$131,947
Depreciation of midstream assets	8,571	1,431
Depreciation of other property and equipment	4,143	724
Depreciation, depletion and amortization expense	$245,083	$134,102
Oil and natural gas properties depreciation, depletion and amortization per BOE	$11.93	$10.69

The increase in depletion of proved oil and natural gas properties of $100.4 million for the six months ended June 30, 2018 as compared to the six months ended June 30, 2017 resulted primarily from higher production levels and an increase in net book value on new reserves added.

General and Administrative Expenses. General and administrative expenses increased $5.2 million from $25.6 million for the six months ended June 30, 2017 to $30.9 million for the six months ended June 30, 2018. The increase was primarily due to an increase in salaries and benefits.

Net Interest Expense. Net interest expense for the six months ended June 30, 2018 was $30.8 million as compared to $20.5 million for the six months ended June 30, 2017, an increase of $10.3 million. This increase was due to a higher interest rate and increased borrowings during the six months ended June 30, 2018 as compared to the six months ended June 30, 2017.

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 six months ended June 30, 2018, we had a cash loss on settlement of derivative instruments of $77.2 million as compared to a cash gain on settlement of derivative instruments of $3.0 million for the six months ended June 30, 2017. For the six months ended June 30, 2018, we had a negative change in the fair value of open derivative instruments of $13.7 million as compared to a positive change of $68.0 million for the six months ended June 30, 2017.

Provision for (Benefit From) Income Taxes. We recorded an income tax provision of $40.5 million and $3.5 million for the six months ended June 30, 2018 and 2017, respectively. The change in our income tax provision was primarily due to the increase in pre-tax book income for the six months ended June 30, 2018, and the change in the valuation allowance for the six months ended June 30, 2017.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been proceeds from our public equity offerings, borrowings under our revolving credit facility, proceeds from the issuance of our 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 six months ended June 30, 2018 and 2017 are presented below:

	Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Net cash provided by operating activities	$764,353	$394,431
Net cash used in investing activities	(1,198,594)	(2,221,476)
Net cash provided by financing activities	435,722	177,059
Net increase (decrease) in cash	$1,481	$(1,649,986)

Operating Activities

Net cash provided by operating activities was $764.4 million for the six months ended June 30, 2018 as compared to $394.4 million for the six months ended June 30, 2017. 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 six months ended June 30, 2018.

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 $1.2 billion and $2.2 billion during the six months ended June 30, 2018 and 2017, respectively.

During the six months ended June 30, 2018, we spent (a) $650.1 million on capital expenditures in conjunction with our development program, in which we drilled 94 gross (86 net) operated horizontal wells, of which 33 gross (31 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 85 gross (75 net) operated horizontal wells into production, of which 41 gross (36 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, (b) $94.5 million on additions to midstream assets, (c) $101.2 million on leasehold acquisitions, (d) $253.1 million for the acquisition of mineral interests and (e) $4.0 million for the purchase of other property and equipment.

During the six months ended June 30, 2017, we spent (a) $291.8 million on capital expenditures in conjunction with our drilling program and related infrastructure projects, in which we drilled 64 gross (55 net) horizontal wells, completed 61 gross (52 net) horizontal wells and participated in the drilling of 11 gross (two net) non-operated wells in the Permian Basin, (b) $4.4 million on additions to midstream assets, (c) $1,861.0 million on leasehold acquisitions, (d) $50.3 million for midstream assets and (e) $13.8 million for the purchase of other property and equipment.

Our investing activities for the six months ended June 30, 2018 and 2017 are summarized in the following table:

	Six Months Ended June 30,	
	2018	2017
	(in thousands)	
Drilling, completion and infrastructure	$(650,058)	$(291,767)
Additions to midstream assets	(94,503)	(4,444)
Acquisition of leasehold interests	(101,216)	(1,860,980)
Acquisition of mineral interests	(253,102)	(122,679)
Acquisition of midstream assets	—	(50,279)
Purchase of other property, equipment and land	(3,978)	(13,825)
Investment in real estate	(110,480)	—
Proceeds from sale of assets	3,879	1,295
Funds held in escrow	10,989	121,391
Equity investments	(125)	(188)
Net cash used in investing activities	$(1,198,594)	$(2,221,476)

Financing Activities

Net cash provided by financing activities for the six months ended June 30, 2018 and 2017 was $435.7 million and $177.1 million, respectively. During the six months ended June 30, 2018, the amount provided by financing activities was primarily attributable to the issuance of $300.0 million of new senior notes and $12.0 million of premium on proceeds of the new senior notes, partially offset by $181.0 million of repayments, net of borrowings, $38.3 million of distributions to non-controlling interest and $12.3 million of dividends to stockholders. The 2017 amount provided by financing activities was primarily attributable to $147.7 million of proceeds from Viper's January 2017 equity offering, partially offset by $45.0 million of repayments, net of borrowings, under Viper's 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 exiting 2025 notes, under an indenture (which, as may be amended or supplemented from time to time, is referred to as the 2025 Indenture) among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee. On July 27, 2017, we exchanged all of the existing 2025 notes for substantially identical notes in the same aggregate principal amount that were registered under the Securities Act.

On January 29, 2018, we issued $300.0 million aggregate principal amount of new 5.375% senior notes due 2025, which we refer to as the new 2025 notes, as additional notes under the 2025 Indenture. The new 2025 notes were issued in a transaction exempt from the registration requirements under the Securities Act. We refer to the new 2025 notes, together with the existing 2025 notes, as the 2025 senior notes. We received approximately $308.4 million in net proceeds, after deducting the initial purchaser’s discount and our estimated offering expenses, but disregarding accrued interest, from the issuance of the new 2025 notes. We used the net proceeds from the issuance of the new 2025 notes to repay a portion of the outstanding borrowings under our revolving credit facility.

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 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 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 new 2025 senior notes, we filed with the SEC our Registration Statement on Form S-4 relating to the exchange offers of the new 2025 senior notes for substantially identical notes registered under the Securities Act. The Registration Statement was declared effective by the SEC on July 18, 2018 and we commenced the exchange offer on July 19, 2018. We expect to close the exchange offer at the end of August 2018.

Second Amended and Restated Credit Facility

Our credit agreement dated November 1, 2013, as amended and restated, with a syndicate of banks, including Wells Fargo, as administrative agent, and its affiliate Wells Fargo Securities, LLC, as sole book runner and lead arranger, provides for a revolving credit facility in the maximum credit amount of $5.0 billion, subject to a borrowing base based on our oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be redetermined, under certain circumstances, annually with an effective date of May 1st, and, under certain circumstances, semi-annually with effective dates of May 1st and November 1st. In addition, we and Wells Fargo may each request up to two interim redeterminations of the borrowing base during any 12-month period. As of June 30, 2018, the borrowing base was set at $2.0 billion, we had elected a commitment amount of $1.0 billion and we had borrowings of $321.5 million outstanding under the revolving credit facility and $678.5 million available for future borrowings under our revolving credit facility.

Diamondback O&G LLC is the borrower under our credit agreement. As of June 30, 2018, the credit agreement is guaranteed by us, Diamondback E&P LLC and Rattler Midstream LLC (formerly known as White Fang Energy LLC) and will also be guaranteed by any of our future subsidiaries that are classified as restricted subsidiaries under the credit agreement. The credit agreement is also secured by substantially all of our assets and the assets of Diamondback O&G LLC and the guarantors.

The outstanding borrowings under the credit agreement bear interest at a per annum 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 0.25% to 1.25% in the case of the alternative base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the least of the maximum credit amount, the borrowing base and the elected commitment amount. 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 loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022.

The 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 net debt to EBITDAX, as defined in the credit agreement	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 November 2017, allows for the issuance of unsecured debt in the form of senior or senior subordinated notes if no default would result from the incurrence of such debt after giving effect thereto and if, in connection with any such issuance, the borrowing base is reduced by 25% of the stated principal amount of each such issuance.

As of June 30, 2018, 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

On July 8, 2014, Viper entered into a secured revolving credit agreement, or revolving credit facility, with Wells Fargo, as administrative agent, certain other lenders, and the Operating Company, as guarantor. On May 8, 2018, the Operating Company assumed all liabilities as borrower under the credit agreement and Viper became a guarantor of the credit agreement. On July 20, 2018, the Operating Company, Viper, Wells Fargo and the other lenders amended and restated the credit agreement to reflect the assumption by the Operating Company. The credit agreement, as amended and restated, provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on Viper's oil and natural gas reserves and other factors (the "borrowing base") of $475.0 million, subject to scheduled semi-annual and other borrowing base redeterminations. The borrowing base is scheduled to be re-

determined semi-annually with effective dates of May 1st and November 1st. In addition, the Operating Company and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. As of June 30, 2018, the borrowing base was set at $475.0 million, and Viper had $350.0 million of outstanding borrowings and $125.0 million available for future borrowings under its revolving credit facility.
The outstanding borrowings under Viper's credit agreement bear interest at a per annum rate elected by the Operating Company that is equal to an alternate base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.75% to 1.75% per annum in the case of the alternate base rate and from 1.75% to 2.75% per annum in the case of LIBOR, in each case depending on the amount of loans and letters of credit outstanding in relation to the commitment, which is defined as the lesser of the maximum credit amount and the borrowing base. The Operating Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the commitment, which fee is also dependent on the amount of loans and letters of credit outstanding in relation to the commitment. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be repaid (a) to the extent the loan amount exceeds the commitment or the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2022. The loan is secured by substantially all of the assets of Viper and the Operating Company.

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

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $400.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

The lenders may accelerate all of the indebtedness under the 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.

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2018 capital budget for drilling and infrastructure of approximately $1.4 billion to $1.5 billion, representing an increase of 66% over our 2017 capital budget. We estimate that, of these expenditures, approximately:

- $1,225.0 million to $1,300.0 million will be spent on drilling and completing 170 to 190 gross (146 to 163 net) horizontal wells across our operated leasehold acreage in the Northern Midland and Southern Delaware Basins, with an average lateral length of approximately 9.300 feet; and

- $175.0 million to $200.0 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

During the six months ended June 30, 2018, our aggregate capital expenditures for our development program were $650.1 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the six months ended June 30, 2018, we spent approximately $354.3 million in cash on acquisitions of leasehold interests and mineral acres. As discussed above, we have entered into a definitive purchase agreement with Ajax to purchase certain oil and natural gas assets for $900.0 million in cash and approximately 2.6 million shares of our common stock, subject to certain adjustments. We expect to fund the cash portion of the consideration for the Pending Ajax Acquisition through a combination of cash on hand, proceeds from the pending Drop-down Transaction, borrowings under our revolving credit facility and/or proceeds from one or more capital markets transactions, which may include debt offerings.

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 11 drilling rigs and five 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 prices and production expectations for 2018, 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 2018. 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 2018 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 a 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 16 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, 2017.

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, 2017.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of June 30, 2018. Please read Note 16 included in Notes to the 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 (Cushing and Magellan East Houston) and Crude Oil - Brent and with natural gas derivative settlements based on NYMEX Henry Hub pricing.

At June 30, 2018 and December 31, 2017, we had a net liability derivative position of $119.8 million and $106.7 million, respectively, related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of June 30, 2018, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position to $161.0 million, an increase of $41.1 million, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability derivative position to $78.7 million, a decrease of $41.1 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 $91.0 million at June 30, 2018) and receivables from the sale of our oil and natural gas production (approximately $167.9 million at June 30, 2018).

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 six months ended June 30, 2018, two purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (30%) and Koch Supply & Trading LP (21%). For the six months ended June 30, 2017, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (37%); Koch Supply & Trading LP (17%); and Enterprise Crude Oil LLC (11%). 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 June 30, 2018, we had six customers that represented approximately 74% of our total joint operations receivables. At December 31, 2017, we had three customers that represented approximately 74% 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 0.25% to 1.25% in the case of the alternative base rate and from 1.25% to 2.25% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base.

As of June 30, 2018, we had $321.5 million in outstanding borrowings under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 3.54%. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately

$3.2 million based on an aggregate of $321.5 million outstanding under our revolving credit facility as of June 30, 2018.

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 June 30, 2018, 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 June 30, 2018, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended June 30, 2018 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, 2017. 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, 2017.

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).

Exhibit Number	Description
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	First Supplemental Indenture, dated as of January 29, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on January 30, 2018).
4.7	Registration Rights Agreement, dated as of January 29, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Securities, LLC (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on January 30, 2018).
4.8	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).
10.1	Sixth Amendment to the Second Amended and Restated Credit Agreement and Third Amendment to Amended and Restated Guaranty and Collateral Agreement, dated as of May 25, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 1, 2018).
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.
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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:	August 9, 2018	/s/ Travis D. Stice
		Travis D. Stice
		Chief Executive Officer
		(Principal Executive Officer)
Date:	August 9, 2018	/s/ Teresa L. Dick
		Teresa L. Dick
		Chief Financial Officer
		(Principal Financial and Accounting Officer)

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