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

FORM 10-Q

☒ **QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE QUARTERLY PERIOD ENDED March 31, 2019
OR

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

Commission File Number 001-35700

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

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

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

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered	Common Stock outstanding as of May 3, 2019
Common Stock	FANG	Nasdaq Global Select Market	164,672,205

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check One):

Large Accelerated Filer	☒	Accelerated Filer	☐
Non-Accelerated Filer	☐	Smaller Reporting Company	☐
		Emerging Growth Company	☐

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. ☐

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

DIAMONDBACK ENERGY, INC.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 2019

TABLE OF CONTENTS

	Page
Glossary of Oil and Natural Gas Terms	ii
Glossary of Certain Other Terms	iv
Cautionary Statement Regarding Forward-Looking Statements	v
PART I. FINANCIAL INFORMATION	
Item 1. Financial Statements (Unaudited)	
Consolidated Balance Sheets	1
Consolidated Statements of Operations	2
Consolidated Statements of Stockholders' Equity	3
Consolidated Statements of Cash Flows	4
Condensed Notes to Consolidated Financial Statements	6
Item 2. Management's Discussion and Analysis of Financial Conditions and Results of Operations	40
Item 3. Quantitative and Qualitative Disclosures about Market Risk	52
Item 4. Controls and Procedures	53
PART II. OTHER INFORMATION	
Item 1. Legal Proceedings	54
Item 1A. Risk Factors	54
Item 6. Exhibits	55
Signatures	57

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.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
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.
2024 Indenture	The indenture relating to the 2024 Senior Notes, dated as of October 28, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
2025 Indenture	The indenture relating to the 2025 Senior Notes, dated as of December 20, 2016, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
NYMEX	New York Mercantile Exchange.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership Agreement	The second amended and restated agreement of limited partnership, dated May 9, 2018, as amended as of May 10, 2018.
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 $1,250 million.
2025 Senior Notes	The Company’s 5.375% senior unsecured notes due 2025 in the aggregate principal amount of $800 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, 2018 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 recent acquisition of certain leasehold acres and other assets from Ajax Resources, LLC and our recent acquisition of Energen Corporation, or Energen, 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.

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

	March 31, 2019	December 31, 2018
	(In millions, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 126	$ 215
Accounts receivable:		
Joint interest and other, net	107	96
Oil and natural gas sales	356	296
Inventories	39	37
Derivative instruments	5	231
Prepaid expenses and other	60	50
Total current assets	693	925
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($9,646 million and $9,670 million excluded from amortization at March 31, 2019 and December 31, 2018, respectively)	23,229	22,299
Midstream assets	762	700
Other property, equipment and land	151	147
Accumulated depletion, depreciation, amortization and impairment	(3,095)	(2,774)
Net property and equipment	21,047	20,372
Equity method investments	150	1
Deferred tax asset	150	97
Investment in real estate, net	114	116
Other assets	114	85
Total assets	$ 22,268	$ 21,596
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$ 180	$ 128
Accrued capital expenditures	485	495
Other accrued liabilities	238	253
Revenues and royalties payable	151	143
Derivative instruments	58	—
Total current liabilities	1,112	1,019
Long-term debt	4,670	4,464
Derivative instruments	16	15
Asset retirement obligations	140	136
Deferred income taxes	1,802	1,785
Other long-term liabilities	14	10
Total liabilities	7,754	7,429
Commitments and contingencies (Note 18)		
Stockholders' equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 164,615,642 issued and outstanding at March 31, 2019; 200,000,000 shares authorized, 164,273,447 issued and outstanding at December 31, 2018	2	2
Additional paid-in capital	13,019	12,936
Retained earnings	752	762
Total Diamondback Energy, Inc. stockholders' equity	13,773	13,700
Non-controlling interest	741	467
Total equity	14,514	14,167
Total liabilities and equity	$ 22,268	$ 21,596

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31,	
	2019	2018
	(In millions, except per share amounts, shares in thousands)	
Revenues:		
Oil sales	$ 743	$ 419
Natural gas sales	29	14
Natural gas liquid sales	70	33
Lease bonus	1	—
Midstream services	19	11
Other operating income	2	2
Total revenues	864	479
Costs and expenses:		
Lease operating expenses	109	37
Production and ad valorem taxes	55	27
Gathering and transportation	12	4
Midstream services	17	11
Depreciation, depletion and amortization	322	115
General and administrative expenses	27	16
Asset retirement obligation accretion	2	1
Other operating expense	1	1
Total costs and expenses	545	212
Income from operations	319	267
Other income (expense):		
Interest expense, net	(46)	(14)
Other income, net	1	3
Loss on derivative instruments, net	(268)	(32)
Gain on revaluation of investment	4	1
Total other expense, net	(309)	(42)
Income before income taxes	10	225
Provision for (benefit from) income taxes	(33)	47
Net income	43	178
Net income attributable to non-controlling interest	33	15
Net income attributable to Diamondback Energy, Inc.	$ 10	$ 163
Earnings per common share:		
Basic	$ 0.06	$ 1.65
Diluted	$ 0.06	$ 1.65
Weighted average common shares outstanding:		
Basic	164,852	98,555
Diluted	165,061	98,769
Dividends declared per share	$ 0.1875	$ 0.125

See accompanying notes to consolidated financial statements.

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

	Common Stock		Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	Shares	Amount				
	($ in millions, shares in thousands)					
Balance December 31, 2017	98,167	$ 1	$ 5,291	$ (37)	$ 327	$ 5,582
Impact of adoption of ASU 2016-01, net of tax		—	—	(9)	(7)	(16)
Unit-based compensation		—	—	—	1	1
Stock-based compensation		—	9	—	—	9
Distribution to non-controlling interest		—	—	—	(19)	(19)
Exercise of stock options and vesting of restricted stock units	443	—	—	—	—	—
Net income		—	—	163	15	178
Balance March 31, 2018	98,610	$ 1	$ 5,300	$ 117	$ 317	$ 5,735
Balance December 31, 2018	164,273	$ 2	$ 12,936	$ 762	$ 467	$ 14,167
Net proceeds from issuance of common units - Viper Energy Partners LP		—	—	—	341	341
Stock-based compensation		—	19	—	—	19
Repurchased shares for tax withholding	(125)	—	(13)	—	—	(13)
Distribution to non-controlling interest		—	—	—	(26)	(26)
Dividend paid		—	—	(20)	—	(20)
Exercise of stock and unit options and awards of restricted stock	468	—	—	—	—	—
Change in ownership of consolidated subsidiaries, net		—	77	—	(74)	3
Net income		—	—	10	33	43
Balance March 31, 2019	164,616	$ 2	$ 13,019	$ 752	$ 741	$ 14,514

See accompanying notes to consolidated financial statements.

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

	Three Months Ended March 31, 2019	Three Months Ended March 31, 2018
	(In millions)	
Cash flows from operating activities:		
Net income	$ 43	$ 178
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for (benefit from) deferred income taxes	(33)	47
Asset retirement obligation accretion	2	1
Depreciation, depletion and amortization	322	115
Amortization of debt issuance costs	1	1
Change in fair value of derivative instruments	285	—
Income from equity investment	—	(2)
Gain on revaluation of investment	(4)	(1)
Equity-based compensation expense	14	7
Changes in operating assets and liabilities:		
Accounts receivable	(63)	6
Inventories	(4)	(13)
Prepaid expenses and other	(9)	(7)
Accounts payable and accrued liabilities	(190)	(17)
Accrued interest	5	11
Revenues and royalties payable	8	13
Net cash provided by operating activities	377	339
Cash flows from investing activities:		
Additions to oil and natural gas properties	(569)	(280)
Additions to midstream assets	(58)	(38)
Purchase of other property, equipment and land	(4)	(2)
Acquisition of leasehold interests	(75)	(16)
Acquisition of mineral interests	(82)	(150)
Investment in real estate	—	(110)
Funds held in escrow	—	11
Equity investments	(149)	—
Net cash used in investing activities	(937)	(585)
Cash flows from financing activities:		
Proceeds from borrowings under credit facility	484	224
Repayment under credit facility	(314)	(308)
Proceeds from senior notes	—	312
Proceeds from joint venture	23	—
Debt issuance costs	(3)	(3)
Proceeds from public offerings	341	—
Repurchased shares for tax withholdings	(13)	—
Dividends to stockholders	(21)	—
Distributions to non-controlling interest	(26)	(19)
Net cash provided by financing activities	471	206
Net decrease in cash and cash equivalents	(89)	(40)
Cash and cash equivalents at beginning of period	215	112
Cash and cash equivalents at end of period	$ 126	$ 72
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$ 17	$ 4

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

	Three Months Ended March 31,	
	2019	**2018**
Supplemental disclosure of non-cash transactions:		
Change in accrued capital expenditures	$ (10)	$ 41
Capitalized stock-based compensation	$ 6	$ 3
Asset retirement obligations acquired	$ 3	$ —

See accompanying notes to consolidated financial statements.

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

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 March 31, 2019, 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 GP LLC, a Delaware limited liability company, and Energen Corporation, an Alabama corporation. The consolidated subsidiaries include these wholly-owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership (the "Partnership"), the Partnership's wholly-owned subsidiary Viper Energy Partners LLC, a Delaware limited liability company (the "Operating Company"), Rattler Midstream LP (formerly known as Rattler Midstream Partners LP), a Delaware limited liability company, Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC), a Delaware limited liability company, and Rattler Midstream Operating LLC's wholly-owned subsidiary Tall City Towers LLC, a Delaware limited liability company ("Tall City").

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 March 31, 2019, the Company owned approximately 54% 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, 2018, 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.

Investments

Equity investments in which the Company exercises significant influence but does not control are accounted for using the equity method. Under the equity method, generally the Company's share of investees' earnings or loss is recognized in the statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company would recognize an impairment provision.

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 was accounted for under the cost method. Effective January 1, 2018, the Partnership adopted Accounting Standards Update 2016-01 which requires the Partnership to measure its investment at fair value which resulted in a downward adjustment of $19 million to record the impact of this adoption. See Note 16—Fair Value Measurements.

New Accounting Pronouncements

Recently Adopted Pronouncements

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. Entities will be required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles and compressors. The Company has completed the process of reviewing and determining the agreements to which this new guidance applies. Upon adoption effective January 1, 2019, the Company recognized approximately $13 million of right-of-use assets, of which the total amount relates to the Company's operating leases.

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 adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-10, "Codification Improvements to Topic 842, Leases". This update provides clarification and corrects unintended application of certain sections in the new lease guidance. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-11, "Lease (Topic 842): Targeted Improvements". This update provides another transition method of allowing entities to initially apply the new lease standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

In December 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-20, "Leases (Topic 842) - Narrow-Scope Improvements for Lessors". This update provides a practical expedient for lessors to elect not to evaluate whether sales taxes and other similar taxes are lessor costs. The update also requires a lessor to exclude from variable payments those costs paid directly by the lessee to third parties and include lessor costs paid by the lessor and reimbursed by the lessee. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity.

See Note 17—Leases for more information on the adoption of these standards.

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. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have an impact on its financial position, results of operations or liquidity because the Company currently accounts for nonemployee share-based transactions in the same manner as employee share-based transactions.

In July 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-09, "Codification Improvements". This update provides clarification and corrects unintended application of the guidance in various sections. The Company adopted this standard effective January 1, 2019. The adoption of this update did not have a material impact on its financial position, results of operations or liquidity.

Accounting Pronouncements Not Yet Adopted

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 its consolidated financial statements since it does not have a history of credit losses.

In August 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-13, "Fair Value Measurement (Topic 820) - Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement". This update modifies the fair value measurement disclosure requirements specifically related to Level 3 fair value measurements and transfers between levels. 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 prospectively. The Company is currently evaluating the impact of the adoption of this update, but does not believe it will have a material impact on its financial position, results of operations or liquidity.

In August 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-15, "Intangibles - Goodwill and Other - Internal - Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract". This update requires the capitalization of implementation costs incurred in a hosting arrangement that is a service contract for internal-use software. Training and certain data conversion costs cannot be capitalized. The entity is required to expense the capitalized implementation costs over the term of the hosting agreement. 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 should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company believes the adoption of this update will not have an impact on its financial position, results of operations or liquidity.

In November 2018, the Financial Accounting Standards Board issued Accounting Standards Update 2018-19, "Codification Improvements to Topic 326, Financial Instruments-Credit Losses". This update clarifies that receivables arising from operating leases are not within the scope of this topic, but rather Topic 842, Leases. 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 an impact on its financial statements since it does not have a history of credit losses.

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 Operating 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 upstream 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 obligations under any of our product sales contracts.

The majority of the Company's midstream revenue agreements have a term greater than one year, and as such the Company has utilized the practical expedient in ASC 606, which states that the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under its revenue agreements, each delivery generally represents a separate performance obligation; therefore, future volumes delivered are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

The remainder of the Company's midstream revenue agreements, which relate to agreements with third parties, are short-term in nature with a term of one year or less. The Company has utilized an additional practical expedient in ASC 606 which exempts it from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of an agreement that has an original expected duration of one year or less.

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 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 March 31, 2019, 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

Tall City Towers LLC

On January 31, 2018, Tall City, 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 $110 million.

Energen Corporation Merger

On November 29, 2018, the Company completed its acquisition of Energen Corporation ("Energen") in an all-stock transaction (the "Merger"), which was accounted for as a business combination. Upon completion of this acquisition, the addition of Energen's assets increased the Company's assets to: (i) over 273,000 net Tier One acres in the Permian Basin, (ii) approximately 7,200 estimated total net horizontal Permian locations, and (iii) approximately 394,000 net acres across the Midland and Delaware Basins. Under the terms of the Merger, each share of Energen common stock was converted into 0.6442 of a share of the Company's common stock. The Company issued approximately 62.8 million shares of its common stock valued at a price of $112.00 per share on the closing date, resulting in total consideration paid by the Company to the former Energen shareholders of approximately $7 billion.

In connection with the closing of the Merger, the Company repaid outstanding principal under Energen's revolving credit facility and assumed all of Energen's other long-term debt. See Note 10—Debt for additional information.

Purchase Price Allocation

The Merger has been accounted for as a business combination, using the acquisition method. The following table represents the preliminary allocation of the total purchase price of Energen to the identifiable assets acquired and the liabilities assumed based on the fair values on the acquisition date, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired. Certain data necessary to complete the purchase price allocation is not yet available, and includes, but is not limited to, valuation of pre-acquisition contingencies, final tax returns that provide the underlying tax basis of Energen's assets and liabilities and final appraisals of assets acquired and liabilities assumed. The Company expects to complete the purchase price allocation during the 12-month period following the acquisition date, during which time the value of the assets and liabilities may be revised as appropriate.

The following table sets forth the Company's preliminary purchase price allocation as of March 31, 2019:

	(In millions)
Consideration:	
Fair value of the Company's common stock issued	$ 7,136
Total consideration	$ 7,136
Fair value of liabilities assumed:	
Current liabilities	$ 349
Asset retirement obligation	105
Long-term debt	1,099
Noncurrent derivative instruments	17
Deferred income taxes	1,403
Other long-term liabilities	7
Amount attributable to liabilities assumed	$ 2,980
Fair value of assets acquired:	
Total current assets	$ 305
Oil and natural gas properties	9,283
Midstream assets	263
Investment in real estate	11
Other property, equipment and land	58
Asset retirement obligation	105
Other postretirement assets	3
Noncurrent income tax receivable, net	76
Other long term assets	12
Amount attributable to assets acquired	$ 10,116

Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the three months ended March 31, 2018 have been prepared to give effect to the Merger as if it had occurred on January 1, 2018. The below information reflects pro forma adjustments for the issuance of the Company's common stock in exchange for Energen's outstanding shares of common stock, as well as pro forma adjustments based on available information and certain assumptions that the Company believes are reasonable, including (i) the Company's common stock issued to convert Energen's outstanding shares of common stock and equity awards as of the closing date of the Merger, (ii) the depletion of Energen's fair-valued proved oil and natural gas properties and (iii) the estimated tax impacts of the pro forma adjustments.

The pro forma results of operations do not include any cost savings or other synergies that may result from the Merger or any estimated costs that have been or will be incurred by the Company to integrate the Energen assets. The pro forma financial data does not include the results of operations for any other acquisitions made during the periods presented, as they were primarily acreage acquisitions and their results were not deemed material.

The pro forma consolidated statement of operations data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Merger taken place on January 1, 2018 and is not intended to be a projection of future results.

	Three Months Ended March 31, 2018	
	(in millions, except per share amounts)	
Revenues	$	838
Income from operations	$	418
Net income	$	268
Basic earnings per common share	$	1.66
Diluted earnings per common share	$	1.65

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 Select 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 March 31, 2019, the Company owned approximately 54% of the Partnership's total units outstanding.

Equity Offerings

On March 1, 2019, the Partnership completed an underwritten public offering of 10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, the Company owned approximately 54% of the total Partnership units then outstanding. The Partnership received net proceeds from this offering of approximately $341 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 outstanding borrowings under the revolving credit facility and finance acquisitions during the period.

As a result of this public offering and the Partnership's issuance of unit-based compensation, the Company's ownership percentage in the Partnership was reduced. During the three months ended March 31, 2019, the Company recorded a $74 million decrease to non-controlling interest in the Partnership with an increase to additional paid-in capital, which represents the difference between the Company's share of the underlying net book value in the Partnership before and after the respective Partnership common unit transactions, on the Company's consolidated balance sheet.

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. Upon completion of the Partnership's July 2018 offering of units, it owned approximately 41% of the outstanding units issued by the Operating Company and the Company owned the remaining approximately 59%. 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 million to the Partnership in respect of its general partner interest and (ii) the Company made a cash capital contribution of $1 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 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 each of the three months ended March 31, 2019 and 2018, the General Partner allocated $1 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 ended March 31, 2019, the Partnership accrued a minimal amount of state income tax expense 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

The Partnership has entered into a secured revolving credit facility with Wells Fargo, as administrative agent sole book runner and lead arranger. See Note 10—Debt for a description of this credit facility.

6. REAL ESTATE ASSETS

The following schedules present the cost and related accumulated depreciation or amortization (as applicable) of the Company's real estate assets including intangible lease assets:

	Estimated Useful Lives	March 31, 2019	December 31, 2018
	(Years)	(in millions)	
Buildings	30	$ 103	$ 103
Tenant improvements	15	4	4
Land	N/A	1	1
Land improvements	15	1	1
Total real estate assets		109	109
Less: accumulated depreciation		(5)	(4)
Total investment in land and buildings, net		$ 104	$ 105

	Weighted Average Useful Lives	March 31, 2019	December 31, 2018
	(Months)	(in millions)	
In-place lease intangibles	45	$ 11	$ 11
Less: accumulated amortization		(4)	(3)
In-place lease intangibles, net		7	8
Above-market lease intangibles	45	4	4
Less: accumulated amortization		(1)	(1)
Above-market lease intangibles, net		3	3
Total intangible lease assets, net		$ 10	$ 11

7. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	March 31, 2019	December 31, 2018
	(in millions)	
Oil and natural gas properties:		
Subject to depletion	$ 13,583	$ 12,629
Not subject to depletion	9,646	9,670
Gross oil and natural gas properties	23,229	22,299
Accumulated depletion	(1,907)	(1,599)
Accumulated impairment	(1,144)	(1,144)
Oil and natural gas properties, net	20,178	19,556
Midstream assets	762	700
Other property, equipment and land	151	147
Accumulated depreciation	(44)	(31)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 21,047	$ 20,372

Balance of costs not subject to depletion:	
Incurred in 2019	$ 186
Incurred in 2018	6,142
Incurred in 2017	2,473
Incurred in 2016	687
Incurred in 2015	158
Total not subject to depletion	$ 9,646

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 $13 million and $7 million for the three months ended March 31, 2019 and 2018, 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 years 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 the full cost 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 revenue including estimated expenditures (based on current costs) to be incurred in developing and producing the proved reserves, 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 March 31, 2019, there was $91 million in exploration costs and development costs and $71 million in capitalized interest that was not subject to depletion. At December 31, 2018, there were $68 million in exploration costs and development costs and $55 million in capitalized interest that was not subject to depletion.

8. ASSET RETIREMENT OBLIGATIONS

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

	Three Months Ended March 31,	
	2019	2018
	(in millions)	
Asset retirement obligations, beginning of period	$ 136	$ 21
Additional liabilities incurred	1	1
Liabilities acquired	3	—
Liabilities settled	(2)	(1)
Accretion expense	2	1
Asset retirement obligations, end of period	140	22
Less current portion	—	1
Asset retirement obligations - long-term	$ 140	$ 21

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.

9. 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. As a result of the amendment, the Company no longer recognizes an equity investment in HMW LLC but instead consolidates its undivided interest in the salt water disposal assets owned by HMW LLC. In exchange for the Company's 25% investment, the Company received a 50% undivided ownership interest in two of the four SWD 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.

For the three months ended March 31, 2019 and the year ended December 31, 2018, the Company did not invest in HMW LLC. For the three months ended March 31, 2019, the Company did not record any income from HMW LLC. For the three months ended March 31, 2018, the Company recorded, in other income, $2 million in income from HMW LLC.

On February 1, 2019, the Company obtained a 10% equity interest in EPIC Crude Holdings, LP ("EPIC"), which is building a pipeline (the "EPIC project") that, once operational, will transport crude and NGL across Texas for delivery into the Corpus Christi market. As of March 31, 2019, the Company has invested $35 million in the EPIC project and recorded no income. The EPIC project is anticipated to be operational in the second half of 2019.

On February 15, 2019, the Company obtained a 10% equity interest in Gray Oak Pipeline, LLC ("Gray Oak"), which is building a pipeline (the "Gray Oak project") that, once operational, will transport crude from the Permian to Corpus Christi on the Texas Gulf Coast. As of March 31, 2019, the Company has invested $115 million in the Gray Oak project and recorded, in other income, $50,000 in income related to interest. The Gray Oak project is anticipated to be operational in the second half of 2019.

On March 29, 2019, the Company executed a short-term promissory note to Gray Oak. The note allows for borrowing by Gray Oak of up to $123 million at 2.52% interest rate with a maturity date of March 31, 2022. There were no borrowings by Gray Oak under the note in the first quarter of 2019.

No impairments were recorded for the Company's equity method investment for the three months ended March 31, 2019 or 2018.

10. DEBT

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

	March 31, 2019	December 31, 2018
	(in millions)	
4.625% Notes due 2021[(1)]	$ 399	$ 400
7.320% Medium-term Notes, Series A, due 2022[(1)]	21	20
4.750 % Senior Notes due 2024	1,250	1,250
5.375 % Senior Notes due 2025	800	800
7.350% Medium-term Notes, Series A, due 2027[(1)]	11	10
7.125% Medium-term Notes, Series B, due 2028[(1)]	109	100
DrillCo Agreement	23	—
Unamortized debt issuance costs	(24)	(27)
Unamortized premium costs	10	10
Revolving credit facility	1,914	1,490
Partnership revolving credit facility	157	411
Total long-term debt	$ 4,670	$ 4,464

(1) At the effective time of the Merger, Energen became a wholly owned subsidiary of the Company and remained the issuer of these notes (the "Energen Notes").

Diamondback Notes

2024 Senior Notes

On October 28, 2016, the Company issued $500 million in aggregate principal amount of 4.750% Senior Notes due 2024 (the "existing 2024 Senior Notes"). The existing 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 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 existing 2024 Senior Notes; provided, however, that the existing 2024 Senior Notes are not guaranteed by the Partnership, the General Partner, Viper Energy Partners LLC or Rattler Midstream Operating LLC, and will not be guaranteed by any of the Company's future unrestricted subsidiaries.

On September 25, 2018, the Company issued $750 million aggregate principal amount of new 4.750% Senior Notes due 2024 (the “New 2024 Notes”), which together with the existing Senior Notes are referred to as the 2024 Senior Notes, as additional notes under, and subject to the terms of, the 2024 Indenture. The New 2024 Notes were issued in a transaction exempt from the registration requirements under the Securities Act. The Company received approximately $741 million in net proceeds, after deducting the initial purchasers’ discount and its estimated offering expenses, but disregarding accrued interest, from the issuance of the New 2024 Notes. The Company used a portion of the net proceeds from the issuance of the New 2024 Notes to repay the outstanding borrowings under its revolving credit facility and used the balance for general corporate purposes, including funding a portion of the cash consideration for the acquisition of assets from Ajax Resources, LLC.

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.

As required under the terms of the registration rights agreement relating to the New 2024 Notes, on March 22, 2019, the Company filed with the SEC its registration Statement on Form S-4 relating to the exchange offer of the New 2024 Notes for substantially identical notes registered under the Securities Act of 1933, as amended.

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 “existing 2025 Senior Notes”). The existing 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 the Company’s existing and future restricted subsidiaries that guarantee its revolving credit facility or certain other debt guarantee the existing 2025 Senior Notes, provided, however, that the existing 2025 Senior Notes are not guaranteed by the Partnership, the General Partner, Viper Energy Partners LLC or Rattler Midstream Operating LLC, and will not be guaranteed by any of the Company’s future unrestricted subsidiaries.

On January 29, 2018, the Company issued $300 million aggregate principal amount of new 5.375% Senior Notes due 2025 (the “New 2025 Notes”), which together with the existing 2025 Senior Notes are referred to as the 2025 Senior 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 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 Senior Notes were issued under an indenture, dated as of December 20, 2016, among the Company, the guarantors party thereto and Wells Fargo Bank, as the trustee (the "2025 Indenture"). The 2025 Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company's ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on capital stock, prepay subordinated indebtedness, sell assets including capital stock of restricted subsidiaries, agree to payment restrictions affecting the Company's restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and natural gas business and designate certain of the Company's subsidiaries as unrestricted subsidiaries.

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

Energen Notes

At the effective time of the Merger, Energen became the Company's wholly owned subsidiary and remained the issuer of $530 million aggregate principal amount of the Energen Notes, issued under an indenture dated September 1, 1996 with The Bank of New York as Trustee (the "Energen Indenture"). The Energen Notes consist of: (1) $400 million aggregate principal amount of 4.625% senior notes due on September 1, 2021, (2) $100 million of 7.125% notes due on February 15, 2028, (3) $20 million of 7.32% notes due on July 28, 2022, and (4) $10 million of 7.35% notes due on July 28, 2027.

The Energen Notes are the senior unsecured obligations of Energen and, post-merger, Energen, as a wholly owned subsidiary of the Company, continues to be the sole issuer and obligor under the Energen Notes. The Energen Notes rank equally in right of payment with all other senior unsecured indebtedness of Energen, including any unsecured guaranties by Energen of the Company's indebtedness and are effectively subordinated to Energen's senior secured indebtedness, including Energen's secured guaranty of all borrowings and other obligations under the Company's revolving credit facility, to the extent of the value of the collateral securing such indebtedness.

The Energen Indenture contains certain covenants that, subject to certain exceptions and qualifications, limit Energen's ability to incur or suffer to exist liens, to enter into sale and leaseback transactions, to consolidate with or merge into any other entity, and to convey, transfer or lease its properties and assets substantially as an entirety to any person or entity. The Energen Indenture does not include a restriction on the payment of dividends.

On November 29, 2018, Energen guaranteed the Company's indebtedness under its credit facility and granted a lien on certain of its assets to secure such indebtedness and, on December 21, 2018, Energen's subsidiaries guaranteed the Company's indebtedness under its credit agreement and granted liens on certain of their assets to secure such indebtedness. As a result of such guarantees, under the terms of the 2024 Indenture and the 2025 Indenture, Energen also guaranteed the 2024 Senior Notes and the 2025 Senior Notes.

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, 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 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 each may request up to two interim redeterminations of the borrowing base during any 12-month period. Effective March 25, 2019, the Company increased its elected commitment amount from $2 billion to $3 billion. As of March 31, 2019, the borrowing base was set at $3 billion, the Company had elected a commitment amount of $3 billion and the Company had $2 billion of outstanding borrowings under the revolving credit facility and $1 billion available for future borrowings under its revolving credit facility.

Diamondback O&G LLC is the borrower under the credit agreement. As of March 31, 2019, the credit agreement is guaranteed by the Company, Diamondback E&P LLC, Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC) and Energen and its subsidiaries 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 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 March 31, 2019 and December 31, 2018, 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 billion and a borrowing base based on the Partnership's oil and natural gas reserves and other factors (the "borrowing base") of $555 million, subject to scheduled semi-annual and other elective 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 March 31, 2019, the borrowing base was set at $555 million, and the Partnership had $157 million of outstanding borrowings and $398 million available for future borrowings under its 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 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.

As of March 31, 2019 and December 31, 2018, the Partnership 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 Partnership's credit agreement upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

Alliance with Obsidian Resources, L.L.C.

The Company entered into a participation and development agreement (the "DrillCo Agreement"), dated September 10, 2018, with Obsidian Resources, L.L.C. ("CEMOF") to fund oil and natural gas development. Funds managed by CEMOF and its affiliates have agreed to commit to funding certain costs out of CEMOF's net production revenue and, for a period of time, to the extent not funded by such revenue, up to an additional $300 million, to fund drilling programs on locations provided by the Company. Subject to adjustments depending on asset characteristics and return expectations of the selected drilling plan, CEMOF will fund up to 85% of the costs associated with new wells drilled under the DrillCo Agreement and is expected to receive an 80% working interest in these wells until it reaches certain payout thresholds equal to a cumulative 9% and then 13% internal rate of return. Upon reaching the final internal rate of return target, CEMOF's interest will be reduced to 15%, while the Company's interest will increase to 85%. As of March 31, 2019, CEMOF had funded approximately $18 million. As of March 31, 2019, six joint wells have been drilled and completed.

11. CAPITAL STOCK AND EARNINGS PER SHARE

Diamondback did not complete any equity offerings during the three months ended March 31, 2019 and March 31, 2018.

Partnership Equity Offerings

On March 1, 2019, the Partnership completed an underwritten public offering of 10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, the Company owned approximately 54% of the Partnership's total units then outstanding. The Partnership received net proceeds from this offering of approximately $341 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 outstanding borrowings under its revolving credit facility and finance acquisitions during the period.

Earnings Per Share

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

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

	Three Months Ended March 31,	
	2019	2018
	($ in millions, except per share amounts, shares in thousands)	
Net income attributable to common stock	$ 10	$ 163
Weighted average common shares outstanding		
Basic weighted average common units outstanding	164,852	98,555
Effect of dilutive securities:		
Potential common shares issuable	209	214
Diluted weighted average common shares outstanding	165,061	98,769
Basic net income attributable to common stock	$ 0.06	$ 1.65
Diluted net income attributable to common stock	$ 0.06	$ 1.65

The Company had the following shares that were excluded from the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per share in future periods:

	Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Restricted stock units	31	—

12. EQUITY-BASED COMPENSATION

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

	Three Months Ended March 31,	
	2019	2018
	(in millions)	
General and administrative expenses	$ 14	$ 8
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	6	3

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the Equity Plan during the three months ended March 31, 2019:

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	324,224	$ 116.01
Granted	435,049	$ 107.30
Vested	(119,477)	$ 109.05
Forfeited	(9,652)	$ 112.27
Unvested at March 31, 2019	630,144	$ 111.37

The aggregate fair value of restricted stock units that vested during the three months ended March 31, 2019 and 2018 was $13 million and $9 million, respectively. As of March 31, 2019, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $55 million. Such cost is expected to be recognized over a weighted-average period of 1.3 years.

Performance Based Restricted Stock Units

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

In March 2019, eligible employees received performance restricted stock unit awards totaling 199,723 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, 2019 to December 31, 2021 and cliff vest at December 31, 2021. In March 2019, eligible employees received performance restricted stock unit awards totaling 32,958 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, 2019 to December 31, 2021 and vest in five equal installments beginning on March 1, 2025.

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 March 2019 awards.

	2019
Grant-date fair value (3-year vesting)	$ 137.22
Grant-date fair value (5-year vesting)	$ 132.48
Risk-free rate	2.55%
Company volatility	35.00%

The following table presents the Company's performance restricted stock units activity under the Equity Plan for the three months ended March 31, 2019:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2018	196,203	$ 169.76
Granted	356,227	$ 131.30
Vested	(123,546)	$ 121.41
Unvested at March 31, 2019(1)	428,884	$ 151.74

(1) A maximum of 857,768 units could be awarded based upon the Company's final TSR ranking.

As of March 31, 2019, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $47 million. Such cost is expected to be recognized over a weighted-average period of 1.4 years.

Stock Appreciation Rights

In connection with the Energen merger, each outstanding stock appreciation right in respect of Energen common stock that was outstanding immediately prior to the effective time of the Merger was converted into a fully vested stock appreciation right in respect of such number of whole shares of Diamondback common stock (rounded down to the nearest whole share) equal to the product of (A) the total number of shares of Energen common stock subject to such stock appreciation right immediately prior to the effective time of the Merger multiplied by (B) the exchange ratio, at an exercise price per share of Diamondback common stock (rounded up to the nearest whole cent) equal to the quotient of (A) the exercise price per share of Energen common stock of such stock appreciation right immediately prior to the effective time of the Merger divided by (B) the exchange ratio. These awards have a three-year requisite service period.

The following table presents a summary of stock appreciation rights activity during the three months ended March 31, 2019:

	Shares	Weighted Average Exercise Price
Outstanding at December 31, 2018	57,721	$ 22.12
Exercised	(7,111)	$ 20.18
Expired	(8,691)	$ 23.29
Outstanding at March 31, 2019	41,919	$ 24.74

Stock Options

In connection with the Energen Merger, each option to purchase shares of Energen common stock that was outstanding immediately prior to the effective time of the Merger was converted into a fully vested option to purchase such number of whole shares of Diamondback common stock (rounded down to the nearest whole share) equal to the product of (A) the total number of shares of Energen common stock subject to such option immediately prior to the effective time of the Merger multiplied by (B) the exchange ratio, at an exercise price per share of Diamondback common stock (rounded up to the nearest whole cent) equal to the quotient of (A) the exercise price per share of Energen common stock of such option immediately prior to the effective time of the Merger divided by (B) the exchange ratio. The exercise price of stock options granted may not be less than the market value of the stock at the date of grant.

The Company estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires the Company to make several assumptions. The expected term of options granted was determined based on the contractual term of the awards at effective time of the merger. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the option at the date of grant. All such amounts represent the weighted-average amounts for each year.

		Weighted Average		
	Options	Exercise Price	Remaining Term	Intrinsic Value
			(in years)	(in millions)
Outstanding at December 31, 2018	332,387	$ 95.04		
Granted	—	$ —		
Outstanding at March 31, 2019	332,387	$ 95.04	2.49	$ 14
Vested and Expected to vest at March 31, 2019	332,387	$ 95.04	2.49	$ 14
Exercisable at March 31, 2019	332,387	$ 95.04	2.49	$ 14

Phantom Units

Under the Viper LTIP, the Board of Directors of the General Partner is authorized to issue phantom units to eligible employees. The Partnership estimates the fair value of phantom units as the closing price of the Partnership's common units on the grant date of the award, which is expensed over the applicable vesting period. Upon vesting the phantom units entitle the recipient one common unit of the Partnership for each phantom unit.

The following table presents the phantom unit activity under the Viper LTIP for the three months ended March 31, 2019.

	Phantom Units	**Weighted Average Grant-Date Fair Value**
Unvested at December 31, 2018	125,053	$ 23.44
Granted	11,001	$ 33.30
Vested	(60,133)	$ 21.38
Unvested at March 31, 2019	75,921	$ 26.51

The aggregate fair value of phantom units that vested during the three months ended March 31, 2019 was $1 million. As of March 31, 2019, the unrecognized compensation cost related to unvested phantom units was $2 million. Such cost is expected to be recognized over a weighted-average period of 0.99 years.

13. 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 $500,000, plus reasonable out-of-pocket expenses. For the three months ended March 31, 2019 and 2018, the Partnership did not pay any amounts under the Advisory Services Agreement. The Advisory Services Agreement was terminated on November 12, 2018; however, the Partnership's payment obligation thereunder continues through the end of the current term in June 2019.

Lease Bonus - The Partnership

During the three months ended March 31, 2019, the Company paid the Partnership $198 in lease bonus payments to extend the term of one lease, reflecting an average bonus of $125 per acre and $3,101 in lease bonus payments for two new leases, reflecting an average bonus of $14,766 per acre. During the three months ended March 31, 2018, the Company did not pay the Partnership any lease bonus payments.

14. INCOME TAXES

The Company’s effective income tax rates were (301.7)% and 20.9% for the three months ended March 31, 2019 and 2018, respectively. Total income tax expense for the three months ended March 31, 2019 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax income primarily due to (i) the revision of estimated deferred taxes recognized by the Partnership as a result of its change in tax status, (ii) current and deferred state income taxes, and (iii) the impact of permanent differences between book and taxable income. The Company recorded a discrete income tax benefit of less than $1 million related to equity-based compensation for the three months ended March 31, 2019 and a discrete benefit of approximately $35 million related to the revision of estimated deferred taxes on the Partnership’s investment in the Operating Company arising from the change in the Partnership’s tax status. The Partnership revised its estimate of deferred taxes on the Partnership’s investment in the Operating Company based on information regarding unitholders’ tax basis which, under IRS reporting rules, was not available until the current period. Total income tax expense for the three months ended March 31, 2018 differed from amounts computed by applying the federal statutory rate to pre-tax income primarily due to state income taxes, net income attributable to the noncontrolling interest, and the impact of permanent differences between book and taxable income.

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 March 31, 2019 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.

15. 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 Magellan East Houston oil price and the WTI Cushing price and for the spread between the Henry Hub natural gas price and the Waha Hub natural gas 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 ICE Brent pricing, and with natural gas derivative settlements based on the New York Mercantile Exchange Henry Hub pricing and liquids derivative settlements based on Mt. Belvieu pricing.

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

As of March 31, 2019, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed.

	2019		2020	
	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
Oil Swaps - WTI Cushing	7,758,000	$ 61.10	—	$ —
Oil Swaps - WTI Magellan East Houston	1,008,000	$ 69.27	—	$ —
Oil Swaps - BRENT	1,375,000	$ 67.22	—	$ —
Oil Basis Swaps - WTI Cushing	12,966,000	$ (5.42)	15,120,000	$ (1.21)
Natural Gas Swaps - Henry Hub	19,250,000	$ 3.06	—	$ —
Natural Gas Basis Swaps - Waha Hub	19,250,000	$ (1.56)	—	$ —
Natural Gas Liquid Swaps - Mont Belvieu	2,070,000	$ 27.30	—	$ —

	2019			2020	
Oil Three-Way Collars	WTI Cushing	Brent	WTI Magellan East Houston	Brent	WTI Magellan East Houston
Volume (Bbls)	5,230,000	1,648,000	1,284,000	3,660,000	2,190,000
Short put price (per Bbl)	$ 37.51	$ 53.88	$ 52.13	$ 50.00	$ 50.00
Floor price (per Bbl)	$ 47.51	$ 63.88	$ 62.13	$ 60.00	$ 60.00
Ceiling price (per Bbl)	$ 63.05	$ 80.09	$ 69.38	$ 74.63	$ 66.90

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 March 31, 2019 and December 31, 2018.

	March 31, 2019	December 31, 2018
	(in millions)	
Gross amounts of assets presented in the Consolidated Balance Sheet	$ 5	$ 231
Net amounts of assets presented in the Consolidated Balance Sheet	5	231
Gross amounts of liabilities presented in the Consolidated Balance Sheet	74	15
Net amounts of liabilities presented in the Consolidated Balance Sheet	$ 74	$ 15

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:

	March 31, 2019	December 31, 2018
	(in millions)	
Current assets: derivative instruments	$ 5	$ 231
Noncurrent assets: derivative instruments	—	—
Total assets	$ 5	$ 231
Current liabilities: derivative instruments	$ 58	$ —
Noncurrent liabilities: derivative instruments	16	15
Total liabilities	$ 74	$ 15

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 March 31,	
	2019	2018
	(in millions)	
Change in fair value of open non-hedge derivative instruments	$ (285)	$ —
Gain (loss) on settlement of non-hedge derivative instruments	17	(32)
Loss on derivative instruments	$ (268)	$ (32)

16. 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.

The Company estimates the fair values of proved oil and natural gas properties assumed in business combinations using discounted cash flow techniques and based on market assumptions as to the future commodity prices, internal estimates of future quantities of oil and natural gas reserves, future estimated rates of production, expected recovery rates and risk-adjustment discounts. The estimated fair values of unevaluated oil and natural gas properties were based on the location, engineering and geological studies, historical well performance, and applicable mineral lease terms. Given the unobservable nature of the inputs, the estimated fair values of oil and natural gas properties assumed is deemed to use Level 3 inputs. The asset retirement obligations assumed as part of business combinations are estimated using the same assumptions and methodology as described below.

The Company estimates asset retirement obligations pursuant to the provisions of the Financial Accounting Standards Board issued Accounting Standards Codification Topic 410, "Asset Retirement and Environmental Obligations". The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with the future plugging and abandonment of wells and related facilities. Given the unobservable nature of the inputs, including plugging costs and useful lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 8—Asset Retirement Obligations for further discussion of the Company's asset retirement obligations.

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 the Partnership's cost method investment. The fair value of the Partnership's investment is determined using quoted market prices. These valuations are Level 1 inputs. 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 March 31, 2019 and December 31, 2018.

	March 31, 2019			December 31, 2018		
	Level 1	Level 2	Level 3	Level 1	Level 2	Level 3
	(in millions)					
Assets:						
Investment	$ 18	$ —	$ —	$ 14	$ —	$ —
Fixed price swaps	—	—	—	—	216	—
Liabilities:						
Fixed price swaps	$ —	$ 69	$ —	$ —	$ —	$ —

The following table summarizes the changes in fair value of the Partnership's cost method investment during the periods presented:

		(in millions)
Value at December 31, 2017	$	34
Impact of adoption of Accounting Standards Update 2016-01		(19)
Gain on investment		1
Value at March 31, 2018	$	16
Value at December 31, 2018	$	14
Gain on investment		4
Value at March 31, 2019	$	18

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:

	March 31, 2019				December 31, 2018			
	Carrying Amount		Fair Value		Carrying Amount		Fair Value	
	(in millions)							
Debt:								
Revolving credit facility	$	1,914	$	1,914	$	1,490	$	1,490
4.625% Notes due 2021(1)	$	399	$	404	$	400	$	393
7.320% Medium-term Notes, Series A, due 2022(1)	$	21	$	22	$	20	$	21
4.750% Senior Notes due 2024	$	1,250	$	1,283	$	1,250	$	1,204
5.375% Senior Notes due 2025	$	800	$	838	$	800	$	782
7.350% Medium-term Notes, Series A, due 2027(1)	$	11	$	11	$	10	$	11
7.125% Medium-term Notes, Series B, due 2028(1)	$	109	$	110	$	100	$	102
Partnership revolving credit facility	$	157	$	157	$	411	$	411
DrillCo Agreement	$	23	$	23	$	—	$	—

(1) At the effective time of the Energen Merger, Energen became a wholly owned subsidiary of the Company and remained the issuer of the Energen Notes. These notes were marked to fair value with the excess being amortized.

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 and the Energen Notes was determined using the March 31, 2019 quoted market price, a Level 1 classification in the fair value hierarchy.

17. LEASES

The Company leases certain drilling rigs, facilities, compression and other equipment.

As discussed in Note 2—Summary of Significant Accounting Policies, the Company adopted ASU 2016-02, ASU 2018-11 and ASU 2019-01 on January 1, 2019 using the optional transition method of adoption. The Company elected a package of practical expedients that together allows an entity to not reassess (i) whether a contract is or contains a lease, (ii) lease classification and (iii) initial direct costs. In addition, the Company elected the following practical expedients: (i) to not reassess certain land easements; (ii) to not apply the recognition requirements under the standard to short-term leases; (iii) to not reassess lease terms for lease terms on leases entered into prior to the effective date of adoption; and (iv) lessor accounting policy election to exclude lessor costs paid directly by the lessee.

For leases where the Company is the lessee, the Company recorded a total of $13 million in right-of-use assets and corresponding new lease liabilities in other on its Condensed Consolidated Balance Sheet representing the present value of its future operating lease payments. Adoption of the standards did not require an adjustment to the opening balance of retained earnings. The discount rate used to determine present value was based on the rate of interest that the Company estimated it would have to pay to borrow (on a collateralized-basis over a similar term) an amount equal to the lease payments in a similar economic environment as of January 1, 2019. The Company is required to reassess the discount rate for any new and modified lease contracts as of the lease effective date.

The right-of-use assets and lease liabilities recognized upon adoption of ASU 2016-02 were based on the lease classifications, lease commitment amounts and terms recognized under the prior lease accounting guidance. Leases with an initial term of twelve months or less are considered short-term leases and are not recorded on the balance sheet.

The following table summarizes operating lease costs for the three months ended March 31, 2019:

	Three Months Ended March 31, 2019	
	(in millions)	
Operating lease costs	$	4

For the three months ended March 31, 2019, cash paid for operating lease liabilities, and reported in cash flows provided by operating activities on the Company's Statement of Condensed Consolidated Cash Flows, was $5 million. During the three months ended March 31, 2019, the Company recorded an additional $8 million of right-of-use assets in exchange for new lease liabilities.

The operating lease right-of-use assets were reported in other assets and the current and noncurrent portions of the operating lease liabilities were reported in other current liabilities and other liabilities, respectively, on the Condensed Consolidated Balance Sheet. As of March 31, 2019, the operating right-of-use assets were $26 million and operating lease liabilities were $26 million, of which $21 million was classified as current. As of March 31, 2019, the weighted average remaining lease term was 1.4 years and the weighted average discount rate was 8.4%.

Schedule of Operating Lease Liability Maturities. The following table summarizes undiscounted cash flows owed by the Company to lessors pursuant to contractual agreements in effect as of March 31, 2019:

	As of March 31, 2019	
	(in millions)	
2019 (April - December)	$	22
2020		4
2021		1
2022		—
2023		—
Thereafter		—
Total lease payments		27
Less: interest		1
Present value of lease liabilities	$	26

For leases in which the Company is the lessor, the Company (i) retained classification of our historical leases as we are not required to reassess classification upon adoption of the new standard, (ii) expensed indirect leasing costs in connection with new or extended tenant leases, the recognition of which would have been deferred under prior accounting guidance and (iii) aggregated revenue from our lease components and non-lease components (comprised of tenant expense reimbursements) into revenue from rental properties.

18. 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.

19. SUBSEQUENT EVENTS

First Quarter 2019 Dividend Declaration

On May 3, 2019, the Board of Directors of the Company declared a cash dividend for the first quarter of 2019 of $0.1875 per share of common stock, payable on June 4, 2019 to its stockholders of record at the close of business on May 28, 2019.

Commodity Contracts

Subsequent to March 31, 2019, the Company entered into new fixed price basis swaps. The Company’s derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing (Cushing and Magellan East Houston) and Crude Oil Brent.

The following tables present the derivative contracts entered into by the Company subsequent to March 31, 2019. When aggregating multiple contracts, the weighted average contract price is disclosed.

	Volume (Bbls/MMBtu)	Fixed Price Swap (per Bbl/MMBtu)
July 2019 - December 2019		
Oil Swaps - WTI	368,000	$ 61.72
Oil Swaps - WTI Magellan East Houston	828,000	$ 65.61
Oil Swaps - BRENT	368,000	$ 69.45
January 2020 - December 2020		
Oil Swaps - WTI	2,562,000	$ 60.63
Oil Swaps - WTI Magellan East Houston	1,464,000	$ 64.25
Oil Swaps - BRENT	1,464,000	$ 66.24

	July 2019 - December 2019	January 2020 - December 2020		
Oil Three-Way Collars	**Brent**	**WTI**	**Brent**	**WTI - Magellan East Houston**
Volume (Bbls)	368,000	2,928,000	2,196,000	2,928,000
Short put price (per Bbl)	$ 50.00	$ 45.00	$ 51.67	$ 50.00
Floor price (per Bbl)	$ 60.00	$ 55.00	$ 61.67	$ 60.00
Ceiling price (per Bbl)	$ 77.50	$ 67.00	$ 74.92	$ 69.90

Gray Oak Promissory Note

As of May 2, 2019, borrowings due the Company totaled $23 million. The note is expected to be repaid in full before the end of the second quarter 2019 when Gray Oak expects to secure bank financing for construction.

Stock Repurchase Program

In May 2019, the Company's board of directors approved a stock repurchase program to acquire up to $2 billion of the Company's outstanding common stock through December 31, 2020. This repurchase program is another component of the Company's capital return program that includes the increased quarterly dividend. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require the Company to acquire any specific number of shares. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors at any time.

Pending Divestiture of Certain Conventional and Non-Core Assets Acquired from Energen

In May 2019, the Company entered into two definitive agreements with unrelated third-party purchasers to divest 103,423 net acres of certain conventional and non-core Permian assets, which were acquired by the Company in the Merger, for an aggregate sale price of $322 million. Both of these divestiture transactions are expected to close by July 1, 2019, subject to continued diligence and closing conditions.

20. GUARANTOR FINANCIAL STATEMENTS

As of March 31, 2019, Diamondback E&P LLC, Diamondback O&G LLC and Energen Corporation and its subsidiaries (the "Guarantor Subsidiaries") are guarantors under the 2024 Indenture and the 2025 Indenture. In connection with the issuance of the 2024 Senior Notes and the 2025 Senior Notes, the Partnership, the General Partner, Viper Energy Partners LLC and Rattler Midstream Operating LLC were designated as Non-Guarantor Subsidiaries. The following presents condensed consolidated financial information for the Company (which for purposes of this Note 20 is referred to as the "Parent"), the Guarantor Subsidiaries and the Non–Guarantor Subsidiaries on a consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

Condensed Consolidated Balance Sheet
March 31, 2019
(in millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 121	$ (5)	$ 10	$ —	$ 126
Accounts receivable, net	—	425	38	—	463
Accounts receivable - related party	—	—	7	(7)	—
Intercompany receivable	3,985	1,356	—	(5,341)	—
Inventories	—	39	—	—	39
Derivative instruments	—	5	—	—	5
Prepaid expenses and other	1	59	—	—	60
Total current assets	4,107	1,879	55	(5,348)	693
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	21,434	1,798	(3)	23,229
Midstream assets	—	762	—	—	762
Other property, equipment and land	—	145	6	—	151
Accumulated depletion, depreciation, amortization and impairment	—	(2,812)	(264)	(19)	(3,095)
Net property and equipment	—	19,529	1,540	(22)	21,047
Equity method investments	—	150	—	—	150
Investment in subsidiaries	12,221	123	—	(12,344)	—
Deferred tax asset	—	—	150	—	150
Investment in real estate, net	—	114	—	—	114
Other assets	—	92	22	—	114
Total assets	$ 16,328	$ 21,887	$ 1,767	$ (17,714)	$ 22,268
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 180	$ —	$ —	$ 180
Intercompany payable	81	5,267	—	(5,348)	—
Accrued capital expenditures	—	485	—	—	485
Other accrued liabilities	39	196	3	—	238
Revenues and royalties payable	—	151	—	—	151
Derivative instruments	—	58	—	—	58
Total current liabilities	120	6,337	3	(5,348)	1,112
Long-term debt	2,036	2,477	157	—	4,670
Derivative instruments	—	16	—	—	16
Asset retirement obligations	—	140	—	—	140
Deferred income taxes	399	1,403	—	—	1,802
Other long-term liabilities	—	14	—	—	14
Total liabilities	2,555	10,387	160	(5,348)	7,754
Commitments and contingencies					
Stockholders' equity	13,773	11,500	819	(12,319)	13,773
Non-controlling interest	—	—	788	(47)	741
Total equity	13,773	11,500	1,607	(12,366)	14,514
Total liabilities and equity	$ 16,328	$ 21,887	$ 1,767	$ (17,714)	$ 22,268

Condensed Consolidated Balance Sheet
December 31, 2018
(in millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 84	$ 108	$ 23	$ —	$ 215
Accounts receivable	—	354	38	—	392
Accounts receivable - related party	—	—	3	(3)	—
Intercompany receivable	4,469	201	—	(4,670)	—
Inventories	—	37	—	—	37
Derivative instruments	—	231	—	—	231
Prepaid expenses and other	3	47	—	—	50
Total current assets	4,556	978	64	(4,673)	925
Property and equipment:					
Oil and natural gas properties, at cost, full cost method of accounting	—	20,586	1,717	(4)	22,299
Midstream assets	—	700	—	—	700
Other property, equipment and land	—	141	6	—	147
Accumulated depletion, depreciation, amortization and impairment	—	(2,514)	(248)	(12)	(2,774)
Net property and equipment	—	18,913	1,475	(16)	20,372
Equity method investments	—	1	—	—	1
Investment in subsidiaries	11,576	112	—	(11,688)	—
Investment in real estate, net	—	116	—	—	116
Deferred tax asset	—	—	97	—	97
Other assets	—	67	18	—	85
Total assets	$ 16,132	$ 20,187	$ 1,654	$ (16,377)	$ 21,596
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 128	$ —	$ —	$ 128
Intercompany payable	—	4,673	—	(4,673)	—
Accrued capital expenditures	—	495	—	—	495
Other accrued liabilities	14	233	6	—	253
Revenues and royalties payable	—	143	—	—	143
Total current liabilities	14	5,672	6	(4,673)	1,019
Long-term debt	2,036	2,017	411	—	4,464
Derivative instruments	—	15	—	—	15
Asset retirement obligations	—	136	—	—	136
Deferred income taxes	382	1,403	—	—	1,785
Other long-term liabilities	—	10	—	—	10
Total liabilities	2,432	9,253	417	(4,673)	7,429
Commitments and contingencies					
Stockholders' equity	13,700	10,934	542	(11,476)	13,700
Non-controlling interest	—	—	695	(228)	467
Total equity	13,700	10,934	1,237	(11,704)	14,167
Total liabilities and equity	$ 16,132	$ 20,187	$ 1,654	$ (16,377)	$ 21,596

Condensed Consolidated Statement of Operations
Three Months Ended March 31, 2019
(in millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 691	$ —	$ 52	$ 743
Natural gas sales	—	25	—	4	29
Natural gas liquid sales	—	66	—	4	70
Royalty income	—	—	60	(60)	—
Lease bonus	—	—	1	—	1
Midstream services	—	19	—	—	19
Other operating income	—	2	—	—	2
Total revenues	—	803	61	—	864
Costs and expenses:					
Lease operating expenses	—	109	—	—	109
Production and ad valorem taxes	—	51	4	—	55
Gathering and transportation	—	12	—	—	12
Midstream services	—	17	—	—	17
Depreciation, depletion and amortization	—	300	16	6	322
General and administrative expenses	15	11	1	—	27
Asset retirement obligation accretion	—	2	—	—	2
Other operating expense	—	1	—	—	1
Total costs and expenses	15	503	21	6	545
Income (loss) from operations	(15)	300	40	(6)	319
Other income (expense)					
Interest expense, net	(10)	(30)	(6)	—	(46)
Other income (expense), net	—	1	—	—	1
Loss on derivative instruments, net	—	(268)	—	—	(268)
Gain on revaluation of investment	—	—	4	—	4
Total other expense, net	(10)	(297)	(2)	—	(309)
Income (loss) before income taxes	(25)	3	38	(6)	10
Provision for income taxes	2	—	(35)	—	(33)
Net income (loss)	(27)	3	73	(6)	43
Net income attributable to non-controlling interest	—	—	40	(7)	33
Net income (loss) attributable to Diamondback Energy, Inc.	$ (27)	$ 3	$ 33	$ 1	$ 10

Condensed Consolidated Statement of Operations
Three Months Ended March 31, 2018
(in millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 364	$ —	$ 55	$ 419
Natural gas sales	—	12	—	2	14
Natural gas liquid sales	—	29	—	4	33
Royalty income	—	—	62	(62)	—
Midstream services	—	11	—	—	11
Other operating income	—	2	—	—	2
Total revenues	—	418	62	(1)	479
Costs and expenses:					
Lease operating expenses	—	37	—	—	37
Production and ad valorem taxes	—	23	4	—	27
Gathering and transportation	—	4	—	—	4
Midstream services	—	11	—	—	11
Depreciation, depletion and amortization	—	100	12	3	115
General and administrative expenses	7	7	2	—	16
Asset retirement obligation accretion	—	1	—	—	1
Other operating expense	—	1	—	—	1
Total costs and expenses	7	184	18	3	212
Income (loss) from operations	(7)	234	44	(4)	267
Other income (expense)					
Interest expense, net	(9)	(3)	(2)	—	(14)
Other income (expense), net	—	3	—	—	3
Loss on derivative instruments, net	—	(32)	—	—	(32)
Gain on revaluation of investment	—	—	1	—	1
Total other expense, net	(9)	(32)	(1)	—	(42)
Income (loss) before income taxes	(16)	202	43	(4)	225
Provision for income taxes	47	—	—	—	47
Net income (loss)	(63)	202	43	(4)	178
Net income attributable to non-controlling interest	—	—	—	15	15
Net income (loss) attributable to Diamondback Energy, Inc.	$ (63)	$ 202	$ 43	$ (19)	$ 163

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2019
(in millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 16	$ 316	$ 45	$ —	$ 377
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(569)	—	—	(569)
Additions to midstream assets	—	(58)	—	—	(58)
Purchase of other property, equipment and land	—	(4)	—	—	(4)
Acquisition of leasehold interests	—	(75)	—	—	(75)
Acquisition of mineral interests	—	—	(82)	—	(82)
Equity investments	—	(149)	—	—	(149)
Net cash used in investing activities	—	(855)	(82)	—	(937)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	424	60	—	484
Repayment under credit facility	—	—	(314)	—	(314)
Proceeds from joint venture	—	23	—	—	23
Debt issuance costs	—	(3)	—	—	(3)
Proceeds from public offerings	—	—	341	—	341
Distributions from subsidiary	37	—	—	(37)	—
Dividends to stockholders	(21)	—	—	—	(21)
Repurchased for tax withholdings	(13)	—	—	—	(13)
Distributions to non-controlling interest	—	—	(63)	37	(26)
Intercompany transfers	18	(18)	—	—	—
Net cash provided by financing activities	21	426	24	—	471
Net increase (decrease) in cash and cash equivalents	37	(113)	(13)	—	(89)
Cash and cash equivalents at beginning of period	84	108	23	—	215
Cash and cash equivalents at end of period	$ 121	$ (5)	$ 10	$ —	$ 126

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2018
(in millions)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 27	$ 263	$ 49	$ —	$ 339
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(280)	—	—	(280)
Additions to midstream assets	—	(38)	—	—	(38)
Purchase of other property, equipment and land	—	(2)	—	—	(2)
Acquisition of leasehold interests	—	(16)	—	—	(16)
Acquisition of mineral interests	—	—	(150)	—	(150)
Funds held in escrow	—	11	—	—	11
Intercompany transfers	(87)	87	—	—	—
Investment in real estate	—	(110)	—	—	(110)
Net cash used in investing activities	(87)	(348)	(150)	—	(585)
Cash flows from financing activities:					
Proceeds from borrowing under credit facility	—	77	147	—	224
Repayment under credit facility	—	(308)	—	—	(308)
Proceeds from senior notes	312	—	—	—	312
Debt issuance costs	(3)	—	—	—	(3)
Distributions from subsidiary	33	—	—	(33)	—
Distributions to non-controlling interest	—	—	(52)	33	(19)
Intercompany transfers	(308)	308	—	—	—
Net cash provided by financing activities	34	77	95	—	206
Net increase (decrease) in cash and cash equivalents	(26)	(8)	(6)	—	(40)
Cash and cash equivalents at beginning of period	54	34	24	—	112
Cash and cash equivalents at end of period	$ 28	$ 26	$ 18	$ —	$ 72

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, 2018. 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 March 31,	
	2019	2018
Oil (MBbls)	68%	74%
Natural gas (MMcf)	15%	12%
Natural gas liquids (MBbls)	17%	14%
	100%	100%

As of March 31, 2019, we had approximately 478,560 net acres, which primarily consisted of approximately 200,239 net acres in the Midland Basin and approximately 163,040 net acres in the Delaware Basin. As of December 31, 2018, we had an estimated 11,868 gross horizontal locations that we believe to be economic at $60 per Bbl West Texas Intermediate, or WTI.

2019 Highlights

First Quarter 2019 Dividend Declaration

On May 3, 2019, our board of directors declared a cash dividend for the first quarter of 2019 of $0.1875 per share of common stock, payable on June 4, 2019 to our stockholders of record at the close of business on May 28, 2019.

Stock Repurchase Program

In May 2019, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock through December 31, 2020. This repurchase program is another component of our capital return program that includes the increased quarterly dividend discussed above. We anticipate that the repurchase program will be funded primarily by free cash flow generated from operations and liquidity events such as the sale of assets. Purchases under the repurchase program may be made from time to time in open market or privately negotiated transactions, and are subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program does not require the Company to acquire any specific number of shares. This repurchase program may be suspended from time to time, modified, extended or discontinued by the board of directors at any time.

Pending Divestiture of Certain Conventional and Non-Core Assets Acquired from Energen

In May 2019, we entered into two definitive agreements with unrelated third-party purchasers to divest 103,423 net acres of certain conventional and non-core Permian assets, which were acquired by us in our merger with Energen, for an aggregate sale price of $322 million. Both of these divestiture transactions are expected to close by July 1, 2019, subject to continued diligence and closing conditions. The assets being sold have estimated full year 2019 net production of approximately 6,500 BOE/d.

Viper's Equity Offering

On March 1, 2019, Viper completed an underwritten public offering of 10,925,000 common units, which included 1,425,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters. Following this offering, we owned approximately 54% of Viper's total units then outstanding. Viper received net proceeds from this offering of approximately $341 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 outstanding borrowings under its revolving credit facility and finance acquisitions during the period.

Operational Update

The following table sets forth the total number of operated horizontal wells drilled and completed during the three months ended March 31, 2019:

	Drilled		**Completed**	
Area	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	43	37	54	50
Delaware Basin	40	36	28	24
Total	83	73	82	74

We are currently operating 23 drilling rigs and eight dedicated frac spreads, with which we expect to complete between 290 to 320 gross horizontal wells with an average lateral length of 9,500 feet for the full year 2019.

Our development program is focused entirely within the Permian Basin, where we continue to focus on long-lateral multi-well pad development. Our horizontal development consists of multiple targeted intervals, primarily within the Wolfcamp and Spraberry formations in the Midland Basin and the Wolfcamp and Bone Springs formations in the Delaware Basin.

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

	Three Months Ended March 31,	
	2019	**2018**
Oil (Bbls)/d	179,056	75,557
Natural gas (Mcf)/d	240,932	72,728
Natural gas liquids (Bbls)/d	43,421	14,929
Total average production per day (BOE)	262,633	102,607

Our average daily production for the three months ended March 31, 2019 as compared to the three months ended March 31, 2018 increased 160,026 BOE/d, or 156.0%.

The following table sets forth our production data by basin for the periods presented:

	Three Months Ended March 31, 2019				Three Months Ended March 31, 2018			
	Midland Basin	Delaware Basin	Other(1)	Total	Midland Basin	Delaware Basin	Other(2)	Total
	(in thousands)							
Production Data:								
Oil (MBbls)	9,984	5,026	1,105	16,115	5,329	1,440	31	6,800
Natural gas (MMcf)	10,172	11,137	375	21,684	4,461	2,006	79	6,546
Natural gas liquids (MBbls)	2,176	1,671	61	3,908	1,094	236	14	1,344
Total (MBoe)	13,855	8,553	1,229	23,637	7,167	2,010	58	9,235

(1) Includes the Central Basin Platform, the Eagle Ford Shale and the Rockies.
(2) Includes the Eagle Ford Shale.

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 March 31,	
	2019	2018
Revenues		
Oil sales	88%	90%
Natural gas sales	3%	3%
Natural gas liquid sales	9%	7%
	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 2018, WTI posted prices ranged from \$44.48 to \$77.41 per Bbl and the Henry Hub spot market price of natural gas ranged from \$2.49 to \$6.24 per MMBtu. During the first three months of 2019, WTI posted prices ranged from \$46.31 to \$60.19 per Bbl and the Henry Hub spot market price of natural gas ranged from \$2.54 to \$4.25 per MMBtu. On March 29, 2019, the WTI posted price for crude oil was \$60.19 per Bbl and the Henry Hub spot market price of natural gas was \$2.73 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 March 31,	
	2019	2018
	(in millions, except Bbl, Mcf and BOE amounts)	
Revenues:		
Oil, natural gas and natural gas liquids	$ 842	$ 466
Lease bonus	1	—
Midstream services	19	11
Other operating income	2	2
Total revenues	864	479
Operating expenses:		
Lease operating expenses	109	37
Production and ad valorem taxes	55	27
Gathering and transportation	12	4
Midstream services	17	11
Depreciation, depletion and amortization	322	115
General and administrative expenses	27	16
Asset retirement obligation accretion	2	1
Other operating expense	1	1
Total expenses	545	212
Income from operations	319	267
Interest expense, net	(46)	(14)
Other income, net	1	3
Loss on derivative instruments, net	(268)	(32)
Gain on revaluation of investment	4	1
Total other expense, net	(309)	(42)
Income before income taxes	10	225
Provision for (benefit from) income taxes	(33)	47
Net income	43	178
Net income attributable to non-controlling interest	33	15
Net income attributable to Diamondback Energy, Inc.	$ 10	$ 163

	Three Months Ended March 31,	
	2019	2018
	(in thousands)	
Production Data:		
Oil (MBbls)	16,115	6,800
Natural gas (MMcf)	21,684	6,546
Natural gas liquids (MBbls)	3,908	1,344
Combined volumes (MBOE)	23,637	9,235
Daily combined volumes (BOE/d)	262,633	102,607
Average Prices:		
Oil (per Bbl)	$ 46.12	$ 61.64
Natural gas (per Mcf)	$ 1.32	$ 2.18
Natural gas liquids (per Bbl)	$ 18.00	$ 24.57
Combined (per BOE)	$ 35.63	$ 50.52
Oil, hedged ($ per Bbl)(1)	$ 46.92	$ 56.80
Natural gas, hedged ($ per MMbtu)(1)	$ 1.49	$ 2.27
Natural gas liquids, hedged ($ per Bbl)(1)	$ 18.19	$ 24.57
Average price, hedged ($ per BOE)(1)	$ 36.38	$ 47.02
Average Costs per BOE:		
Lease operating expense	$ 4.61	$ 4.04
Production and ad valorem taxes	2.33	2.96
Gathering and transportation expense	0.51	0.42
General and administrative - cash component	0.55	0.96
Total operating expense - cash	$ 8.00	$ 8.38
General and administrative - non-cash component	$ 0.59	$ 0.81
Depreciation, depletion and amortization	13.62	12.48
Interest expense, net	1.95	1.48
Total expenses	$ 16.16	$ 14.77
Average realized oil price ($/Bbl)	$ 46.12	$ 61.64
Average NYMEX ($/Bbl)	$ 54.82	$ 62.91
Differential to NYMEX	(8.70)	(1.27)
Average realized oil price to NYMEX	84%	98%
Average realized natural gas price ($/Mcf)	$ 1.32	$ 2.18
Average NYMEX ($/Mcf)	$ 2.92	$ 3.08
Differential to NYMEX	(1.60)	(0.90)
Average realized natural gas price to NYMEX	45%	71%
Average realized natural gas liquids price ($/Bbl)	$ 18.00	$ 24.57
Average NYMEX oil price ($/Bbl)	$ 54.82	$ 62.91
Average realized natural gas liquids price to NYMEX oil price	33%	39%

(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 March 31, 2019 and 2018

Oil, Natural Gas and Natural Gas Liquids Revenues. Our oil, natural gas and natural gas liquids revenues increased by approximately $376 million, or 81%, to $842 million for the three months ended March 31, 2019 from $466 million for the three months ended March 31, 2018. 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 160,026 BOE/d to 262,633 BOE/d during the three months ended March 31, 2019 from 102,607 BOE/d during the three months ended March 31, 2018. The total increase in revenue of approximately $376 million is largely attributable to higher oil, natural gas and natural gas liquids production volumes partially offset by lower average sales prices for the three months ended March 31, 2019 as compared to the three months ended March 31, 2018. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 9,314,965 Bbls of oil, 15,138,340 Mcf of natural gas and 2,564,292 Bbls of natural gas liquids for the three months ended March 31, 2019 as compared to the three months ended March 31, 2018.

The net dollar effect of the decreases in prices of approximately $295 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 $671 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 millions)
Effect of changes in price:			
Oil	$ (15.52)	16,115	$ (250)
Natural gas	$ (0.87)	21,684	(19)
Natural gas liquids	$ (6.57)	3,908	(26)
Total revenues due to change in price			$ (295)

	Change in production volumes(1)	Prior period Average Prices	Total net dollar effect of change
			(in millions)
Effect of changes in production volumes:			
Oil	9,315	$ 61.64	$ 575
Natural gas	15,138	$ 2.18	33
Natural gas liquids	2,564	$ 24.57	63
Total revenues due to change in production volumes			671
Total change in revenues			$ 376

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

Realized pricing is expected to improve beginning in the second quarter of 2019 as our fixed differential contracts roll off and convert to commitments on new-build long-haul pipelines or move closer to current Midland market price. Based on current market differentials and estimated in-basin gathering cost, we expect to realize approximately 88% to 92% of WTI in the future remainder of 2019 and approximately 100% of WTI in 2020.

Lease Bonus Revenue. Lease bonus revenue was $1 million for the three months ended March 31, 2019, which was attributable to lease bonus payments to extend the term of four leases, reflecting an average bonus of $507 per acre, and lease bonus payments on four new leases, reflecting an average bonus of $16,680 per acre. We did not receive any lease bonus revenue for the three months ended March 31, 2018.

Midstream Services Revenue. Midstream services revenue was $19 million for the three months ended March 31, 2019, an increase of $8 million as compared to $11 million for the three months ended March 31, 2018. 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 Expenses. Lease operating expenses were $109 million ($4.61 per BOE) for the three months ended March 31, 2019 as compared to $37 million ($4.04 per BOE) for the three months ended March 31, 2018. The increase in lease operating expense and leases operating expense per BOE was a result of the Energen acquisition.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $55 million for the three months ended March 31, 2019, an increase of $28 million, or 104%, from $27 million for the three months ended March 31, 2018. 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 March 31, 2019, our production and ad valorem taxes per BOE decreased by $0.63 as compared to the three months ended March 31, 2018, primarily due to a higher percentage increase in production volumes as compared to production and ad valorem tax expense.

Midstream Services Expense. Midstream services expense was $17 million for the three months ended March 31, 2019, an increase of $6 million as compared to $11 million for the three months ended March 31, 2018. 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 $207 million, or 180%, to $322 million for the three months ended March 31, 2019 from $115 million for the three months ended March 31, 2018.

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

	Three Months Ended March 31,	
	2019	**2018**
	(in millions, except BOE amounts)	
Depletion of proved oil and natural gas properties	$ 311	$ 109
Depreciation of midstream assets	8	5
Depreciation of other property and equipment	3	1
Depreciation, depletion and amortization expense	$ 322	$ 115
Oil and natural gas properties depreciation, depletion and amortization per BOE	$ 13.17	$ 11.80

The increase in depletion of proved oil and natural gas properties of $202 million for the three months ended March 31, 2019 as compared to the three months ended March 31, 2018 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 $11 million from $16 million for the three months ended March 31, 2018 to $27 million for the three months ended March 31, 2019. The increase was primarily due to an increase in salaries and benefits as a result of increased head count.

Net Interest Expense. Net interest expense for the three months ended March 31, 2019 was $46 million as compared to $14 million for the three months ended March 31, 2018, an increase of $32 million. This increase was primarily due to a higher interest rate and increased average borrowings under our credit facility during the three months ended March 31, 2019 as compared to the three months ended March 31, 2018 as well as an increase in interest expense of $5 million related to our DrillCo Agreement.

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 March 31, 2019, we had a cash gain on settlement of derivative instruments of $17.0 million as compared to a cash loss on settlement of derivative instruments of $32 million for the three months ended March 31, 2018. For the three months ended March 31, 2019, we had a negative change in the fair value of open derivative instruments of $285 million as compared to no change during the three months ended March 31, 2018.

Provision for Income Taxes. We recorded an income tax benefit of $33 million for the three months ended March 31, 2019 as compared to an income tax provision of $47 million for the three months ended March 31, 2018. The change in our income tax provision was primarily due to the decrease in pre-tax book income for the three months ended March 31, 2019 and a discrete income tax benefit resulting from the revision of estimated deferred taxes recognized as a result of Viper's change in tax status.

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 three months ended March 31, 2019 and 2018 are presented below:

	Three Months Ended March 31,	
	2019	2018
	(in millions)	
Net cash provided by operating activities	$ 377	$ 339
Net cash used in investing activities	(937)	(585)
Net cash provided by financing activities	471	206
Net decrease in cash	$ (89)	$ (40)

Operating Activities

Net cash provided by operating activities was $377 million for the three months ended March 31, 2019 as compared to $339 million for the three months ended March 31, 2018. 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 production growth partially offset by a decrease in average prices during the three months ended March 31, 2019.

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 $937 million and $585 million during the three months ended March 31, 2019 and 2018, respectively.

During the three months ended March 31, 2019, we spent (a) $569 million on capital expenditures in conjunction with our development program, in which we drilled 83 gross (73 net) operated horizontal wells, of which 40 gross (36 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 82 gross (74 net) operated horizontal wells into production, of which 28 gross (24 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, (b) $58 million on additions to midstream assets, (c) $75 million on leasehold acquisitions, (d) $82 million for the acquisition of mineral interests, (e) $4 million for the purchase of other property and equipment and (f) $149 million on equity investments.

During the three months ended March 31, 2018, we spent (a) $280 million on capital expenditures in conjunction with our drilling program and related infrastructure projects, in which we drilled 41 gross (36 net) operated horizontal wells, of which 14 gross (13 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 35 gross (30 net) operated horizontal wells into production, of which six gross (six net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, (b) $38 million on additions to midstream assets, (c) $16 million on leasehold acquisitions, (d) $150 million for mineral interests acquisitions and (e) $2 million for the purchase of other property and equipment.

Our investing activities for the three months ended March 31, 2019 and 2018 are summarized in the following table:

	Three Months Ended March 31,	
	2019	2018
	(in millions)	
Drilling, completion and infrastructure	$ (569)	$ (280)
Additions to midstream assets	(58)	(38)
Acquisition of leasehold interests	(75)	(16)
Acquisition of mineral interests	(82)	(150)
Purchase of other property, equipment and land	(4)	(2)
Investment in real estate	—	(110)
Funds held in escrow	—	11
Equity investments	(149)	—
Net cash used in investing activities	$ (937)	$ (585)

Financing Activities

Net cash provided by financing activities for the three months ended March 31, 2019 and 2018 was $471 million and $206 million, respectively. During the three months ended March 31, 2019, the amount provided by financing activities was primarily attributable to $170 million of borrowings, net of repayments, under our credit facility, an aggregate of $341 million of net proceeds from Viper's public offering, $26 million of distributions to non-controlling interest, $21 million of dividends to stockholders and $23 million in proceeds from joint ventures. The 2018 amount provided by financing activities was primarily attributable to the issuance of $300 million of new senior notes and $12 million of premium on proceeds of the new senior notes described below, partially offset by $84 million of repayments, net of borrowings, and $19 million in distributions to non-controlling interest.

2024 Senior Notes

On October 28, 2016, we issued $500 million in aggregate principal amount of 4.750% senior notes due 2024, which we refer to as the existing 2024 senior notes, under an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, which we refer to as the 2024 indenture. On September 25, 2018, we issued $750 million aggregate principal amount of new 4.750% senior notes due 2024, which we refer to as the new 2024 notes and, together with the existing 2024 senior notes, as the 2024 senior notes, as additional notes under, and subject to the terms of, the 2024 indenture.

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 Operating LLC, and will not be guaranteed by any of our future unrestricted subsidiaries.

As required under the terms of the registration rights agreements relating to the new 2024 senior notes, on March 22, 2019, we filed with the SEC our Registration Statement on Form S-4 relating to the exchange offers of the new 2024 senior notes for substantially identical notes registered under the Securities Act.

For additional information regarding the 2024 senior notes, see Note 10—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-Q.

2025 Senior Notes

On December 20, 2016, we issued $500 million in aggregate principal amount of 5.375% senior notes due 2025, which we refer to as the exiting 2025 notes, under an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee. On January 29, 2018, we issued $300 million aggregate principal amount of new 5.375% senior notes due 2025, which we refer to as the new 2025 notes and, together with the existing 2025 notes, as additional notes under the 2025 indenture.

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 Operating LLC, and will not be guaranteed by any of our future unrestricted subsidiaries.

For additional information regarding the 2025 senior notes, see Note 10—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-Q.

Energen Notes

At the effective time of the merger, Energen became our wholly owned subsidiary and remained the issuer of an aggregate principal amount of $530 million in notes, which we refer to as the Energen Notes, issued under an indenture dated September 1, 1996 with The Bank of New York as Trustee, which we refer to as the Energen Indenture. The Energen Notes consist of: (a) $400 million aggregate principal amount of 4.625% senior notes due on September 1, 2021, (b) $100 million of 7.125% notes due on February 15, 2028, (c) $20 million of 7.320% notes due on July 28, 2022, and (d) $10 million of 7.35% notes due on July 28, 2027.

The Energen Notes are the senior unsecured obligations of Energen and, post-merger, Energen, as our wholly owned subsidiary, continues to be the sole issuer and obligor under the Energen Notes. The Energen Notes rank equally in right of payment with all other senior unsecured indebtedness of Energen, including any unsecured guaranties by Energen of our indebtedness, and are effectively subordinated to Energen's senior secured indebtedness, including Energen's secured guaranty of all borrowings and other obligations under our revolving credit facility, to the extent of the value of the collateral securing such indebtedness.

For additional information regarding the Energen Notes, See Note 10—Debt included in Notes to the Consolidated Financial Statements included elsewhere in this Form 10-Q.

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 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. Effective March 25, 2019, the Company elected to increase its commitment amount from $2 billion to $3 billion. As of March 31, 2019, the borrowing base was set at $3 billion, we had elected a commitment amount of $3 billion and we had $2 billion in outstanding borrowings and $1 billion available for future borrowings under our revolving credit facility.

Diamondback O&G LLC is the borrower under our credit agreement. As of March 31, 2019, the credit agreement is guaranteed by us, Diamondback E&P LLC, Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC) and Energen Corporation and its subsidiaries 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 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 March 31, 2019, 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 billion and a borrowing base based on Viper's oil and natural gas reserves and other factors (the "borrowing base") of $555 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 March 31, 2019, the borrowing base was set at $555 million, and Viper had $157 million of outstanding borrowings and $398 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 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 2019 capital budget for drilling and infrastructure of approximately $2.7 billion to $3.0 billion. We estimate that, of these expenditures, approximately:

- $2.3 billion to $2.55 billion will be spent on drilling and completing 290 to 320 gross (255 to 280 net) horizontal wells across our operated leasehold acreage in the Northern Midland and Southern Delaware Basins, with an average lateral length of approximately 9,500 feet;
- $225 million to $250 million will be spent on midstream infrastructure excluding the cost of long-haul pipeline equity investments; and
- $175 million to $200 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

During the three months ended March 31, 2019, our aggregate capital expenditures for our development program were $569 million. Additionally during the three months ended March 31, 2019, we spent approximately $157 million in cash on acquisitions of leasehold interests and mineral acres. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

In May 2019, our board of directors approved a stock repurchase program to acquire up to $2 billion of our outstanding common stock through December 31, 2020. We intend to purchase shares under the repurchase program opportunistically with available funds primarily from cash flow from operations and liquidity events such as the sale of assets while maintaining sufficient liquidity to fund our capital expenditure programs.

The amount and timing of our 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 23 drilling rigs and eight 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 2019, 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 2019. 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 2019 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 18 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, 2018.

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, 2018.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of March 31, 2019. Please read Note 18 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 three-way 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 and Waha Hub pricing.

At March 31, 2019, we had a net liability derivative position of $69 million as compared to a net asset derivative position of $216 million at December 31, 2018 related to our price swap, price basis swap derivatives and three-way collars. Utilizing actual derivative contractual volumes under our fixed price swaps as of March 31, 2019, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position to $188 million, an increase of $119 million, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability derivative position to a net asset position of $50 million, a decrease of $119 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 $107 million at March 31, 2019) and receivables from the sale of our oil and natural gas production (approximately $356 million at March 31, 2019).

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 three months ended March 31, 2019, three purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (25%), Plains Marketing LP (25%) and Occidental Energy Marketing Inc (10%). For the three months ended March 31, 2018, two purchasers each accounted for more than 10% of our revenue: Shell Trading (US) Company (30%) and Koch Supply & Trading LP (20%). 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 March 31, 2019, we had nine customers that represented approximately 70% of our total joint operations receivables. At December 31, 2018, we had four customers that represented approximately 82% 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 March 31, 2019, we had $2 billion outstanding borrowings under our revolving credit facility. Our weighted average interest rate on borrowings under our revolving credit facility was 4.24% as of March 31, 2019. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $19 million based on the $2 billion outstanding under our revolving credit facility as of such date.

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 March 31, 2019, 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 March 31, 2019, 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 March 31, 2019 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. While the outcome of the pending litigation, disputes or claims cannot be predicted with certainty, in the opinion of our management, none of these matters, 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, 2018.

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit Number	Description
2.1#	Agreement and Plan of Merger, dated as of August 14, 2018, by and among Diamondback Energy, Inc., Sidewinder Merger Sub Inc. and Energen Corporation (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on August 15, 2018).
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	Certificate of Amendment No. 1 of the Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 12, 2016).
3.3	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).
3.4	First Amendment to the Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on April 27, 2018).
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	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).
4.3	First Supplemental Indenture, dated as of September 25, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on October 1, 2018).
4.4	Second Supplemental Indenture for the 4.750% Senior Notes due 2024, dated as of October 12, 2018, among Sidewinder Merger Sub Inc., a subsidiary of the Company, the Company, the other guarantors under the indenture and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2019).
4.5	Third Supplemental Indenture for the 4.750% Senior Notes due 2024, dated as of January 28, 2019, among Energen Corporation, Energen Resources Corporation, and EGN Services, Inc., each a direct or indirect subsidiary of the Company, the Company, the other guarantors under the indenture and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2019).
4.6	Registration Rights Agreement, dated September 25, 2018, among Diamondback Energy, Inc., the guarantors party thereto and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Goldman Sachs & Co. LLC (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on October 1, 2018).
4.7	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).
4.8	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).
4.9	Second Supplemental Indenture for the 5.375% Senior Notes due 2025, dated as of October 12, 2018, among Sidewinder Merger Sub Inc., a subsidiary of the Company, the Company, the other guarantors and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.8 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2019).
4.10	Third Supplemental Indenture for the 5.375% Senior Notes due 2025, dated as of January 28, 2019, among Energen Corporation, Energen Resources Corporation, and EGN Services, Inc., each a direct or indirect subsidiary of the Company, the Company, the other guarantors under the indenture and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.9 to the Form 10-K, File No. 001-35700, filed by the Company with the SEC on February 25, 2019).
4.11	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).

Exhibit Number	Description
4.12	Registration Rights Agreement, dated October 31, 2018, by and between Diamondback Energy, Inc. and Ajax Resources, LLC (incorporated by reference to Exhibit 4.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 7, 2018).
4.13	Form of Indenture, dated September 1, 1996, between Energen and The Bank of New York as trustee (incorporated by reference to Exhibit 4(i) to Energen's Registration Statement on Form S-3, Registration No. 333-11239, filed with the SEC on August 30, 1996).
10.1	Tenth Amendment to Second Amended and Restated Credit Agreement, dated as of March 25, 2019, between Diamondback, 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. 00 1-35700), filed by the Company with the SEC on March 29, 2019).
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. The instance document does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

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* Filed herewith.

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

\# Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The registrant hereby undertakes to furnish supplementally copies of any of the omitted schedules upon request by the SEC.

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:	May 9, 2019	/s/ Travis D. Stice
		Travis D. Stice Chief Executive Officer (Principal Executive Officer)
Date:	May 9, 2019	/s/ Kaes Van’t Hof
		Kaes Van’t Hof Chief Financial Officer (Principal Financial Officer)

EXHIBIT 31.1

CERTIFICATION

I, Travis D. Stice, certify that:

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

Date: May 9, 2019

/s/ Travis D. Stice

Travis D. Stice
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Kaes Van't Hof, certify that:

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

Date: May 9, 2019

/s/ Kaes Van't Hof

Kaes Van't Hof
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF PERIOD REPORT

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

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

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

Date: May 9, 2019	/s/ Travis D. Stice
	Travis D. Stice
	Chief Executive Officer

EXHIBIT 32.2

CERTIFICATION OF PERIOD REPORT

In connection with the Quarterly Report on Form 10-Q of Diamondback Energy, Inc. (the "Company"), as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Kaes Van't Hof, Chief Financial Officer of Diamondback Energy, Inc., certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that, to the best of my knowledge:

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

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

Date: May 9, 2019

/s/ Kaes Van't Hof

Kaes Van't Hof

Chief Financial Officer