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

FORM 10-K

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

For the fiscal year ended December 31, 2020

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)

DE	**45-4502447**
(State or Other Jurisdiction of Incorporation or Organization)	**(I.R.S. Employer Identification Number)**
500 West Texas Suite 1200 Midland, TX	**79701**
(Address of principal executive offices)	**(Zip code)**

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

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	FANG	The Nasdaq Stock Market LLC (NASDAQ Global Select Market)

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

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 preceding 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 (§ 232.405 of this chapter) 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, a 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:

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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates of registrant as of June 30, 2020 was approximately $6.6 billion.

As of February 19, 2021, 158,015,647 shares of the registrant's common stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Diamondback Energy, Inc.'s Proxy Statement for the 2021 Annual Meeting of Stockholders are incorporated by reference in Items 10, 11, 12, 13 and 14 of Part III of this Form 10-K.

DIAMONDBACK ENERGY, INC.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2020

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and natural gas industry terms used in this Annual Report on Form 10-K, which we refer to as this Annual Report or this report:

3-D seismic	Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.
Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl or barrel	One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
BOE	One barrel of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	Barrels of oil equivalent per day.
Brent	Brent sweet light crude oil.
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.
Condensate	Liquid hydrocarbons associated with the production that is primarily natural gas.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Developed acreage	Acreage assignable to productive wells.
Development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves.
Differential	An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.
Dry hole or dry well	A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.
Estimated Ultimate Recovery or EUR	Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.
Exploitation	A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.
Field	An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
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.
Fracturing	The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
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.
MBbls	One thousand barrels of crude oil or other liquid hydrocarbons.
MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
Mcf	One thousand cubic feet of natural gas.
Mcf/d	One thousand cubic feet of natural gas per day.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	One million British Thermal Units.
MMcf	Million cubic feet of natural gas.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

Net royalty acres	Gross acreage multiplied by the average royalty interest.
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.
Play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
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.
PUD	Proved undeveloped.
Productive well	A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
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 developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
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.
Proved undeveloped reserves	Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
Recompletion	The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
Reserves	Reserves are 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 should not be 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 crude oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Resource play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
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, which may be subject to expiration.
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.
Tight formation	A formation with low permeability that produces natural gas with very low flow rates for long periods of time.
Undeveloped acreage	Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
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.
WTI	West Texas Intermediate.

GLOSSARY OF CERTAIN OTHER TERMS

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

ASU	Accounting Standards Update.
Company	Diamondback Energy, Inc., a Delaware corporation, together with its subsidiaries.
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173).
EPA	U.S. Environmental Protection Agency.
Equity Plan	The Company's Equity Incentive Plan.
Exchange Act	The Securities Exchange Act of 1934, as amended.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
GAAP	Accounting principles generally accepted in the United States.
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.
2025 Senior Notes	The Company's 5.375% senior unsecured notes due 2025 in the aggregate principal amount of $800 million.
December 2019 Notes Indenture	The indenture relating to the December 2019 Notes dated as of December 5, 2019, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
December 2019 Notes	The Company's 2.875% senior unsecured notes due 2024 in the aggregate principal amount of $1.0 billion, the Company's 3.250% senior unsecured notes due 2026 in the aggregate principal amount of $800 million and the Company's 3.500% senior unsecured notes due 2029 in the aggregate principal amount of $1.2 billion.
May 2020 Notes	The Company's 4.750% Senior Notes due 2025 in the aggregate principal amount of $500.0 million issued on May 26, 2020 under the December 2019 Notes Indenture (defined above) and the related second supplemental indenture.
NYMEX	New York Mercantile Exchange.
Rattler	Rattler Midstream LP, a Delaware limited partnership.
Rattler's general partner	Rattler Midstream GP LLC, a Delaware limited liability company; the general partner of Rattler Midstream LP and a wholly owned subsidiary of the Company.
Rattler LLC	Rattler Midstream Operating LLC, a Delaware limited liability company and a subsidiary of Rattler.
Rattler LTIP	Rattler Midstream LP Long-Term Incentive Plan.
Rattler Offering	Rattler's initial public offering.
Ryder Scott	Ryder Scott Company, L.P.
SEC	Securities and Exchange Commission.
SEC Prices	Unweighted arithmetic average oil and natural gas prices as of the first day of the month for the most recent 12 months as of the balance sheet date.
Securities Act	The Securities Act of 1933, as amended.
Senior Notes	The 2025 Senior Notes, the December 2019 Notes and the May 2020 Notes.
Viper	Viper Energy Partners LP, a Delaware limited partnership.
Viper's general partner	Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership.
Viper LLC	Viper Energy Partners LLC, a Delaware limited liability company and a subsidiary of the Partnership.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this Annual Report are "forward-looking statements" as defined by the SEC. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, 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.

Forward-looking statements may include statements about:

- the volatility of realized oil and natural gas prices and the extent and duration of price reductions and increased production by the Organization of the Petroleum Exporting Counties, or OPEC, members and other oil exporting nations;
- the threat, occurrence, potential duration or other implications of epidemic or pandemic diseases, including the ongoing COVID-19 pandemic, any government responses thereto and logistical challenges and the supply chain disruptions during the ongoing COVID-10 pandemic;
- any impact of the ongoing COVID-19 pandemic on the health and safety of our employees;
- logistical challenges and the supply chain disruptions;
- changes in general economic, business or industry conditions;
- conditions in the capital, financial and credit markets and our ability to obtain capital needed for development and exploration operations on favorable terms or at all;
- conditions of the U.S. oil and natural gas industry and the effect of U.S. energy, monetary and trade policies;
- U.S. and global economic conditions and political and economic developments, including the effects of the recent U.S. presidential and congressional elections on energy and environmental policies;
- our ability to execute our business and financial strategies;
- exploration and development drilling prospects, inventories, projects and programs;
- levels of production;
- the impact of reduced drilling activity on our exploration and development drilling prospects, inventories, projects and programs;
- regional supply and demand factors, delays, curtailments delays or interruptions of production, and any governmental order, rule of regulation that may impose production limits;
- our ability to replace our oil and natural gas reserves;
- our ability to identify, complete and effectively integrate acquisitions of properties or businesses, including our pending merger with QEP Resources, Inc., or QEP, and the Pending Guidon Acquisition (defined below);
- competition in the oil and natural gas industry;
- title defects in our oil and natural gas properties;
- uncertainties with respect to identified drilling locations and estimates of reserves;
- the availability or cost of rigs, equipment, raw materials, supplies, oilfield services or personnel;
- the impact of severe weather conditions, including the recent winter storms in the Permian Basin, on our production;
- restrictions on the use of water;
- the availability of transportation, pipeline and storage facilities;
- our ability to comply with applicable government laws and regulations and to obtain permits and governmental approvals;
- federal and state legislative and regulatory initiatives relating to hydraulic fracturing, including the effect of existing and future laws and governmental regulations;

- our environmental initiatives and targets;
- future operating results;
- future dividends to our stockholders;
- impact of any impairment charges;
- lease operating expenses, general and administrative costs and finding and development costs;
- operating hazards;
- civil unrest, terrorist attacks and cyber threats;
- the effects of litigation relating to our pending merger with QEP and any future litigation;
- our ability to keep up with technological advancements;
- capital expenditure plans;
- other plans, objectives, expectations and intentions; and
- certain other factors discussed elsewhere in this report.

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. 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.

PART I

Except as noted, in this Annual Report on Form 10-K, we refer to Diamondback, together with its consolidated subsidiaries, as "we," "us," "our," or "the Company". This Annual Report includes certain terms commonly used in the oil and natural gas industry, which are defined above in the "Glossary of Oil and Natural Gas Terms."

ITEMS 1 and 2. BUSINESS AND PROPERTIES

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. This basin, which is one of the major producing basins in the United States, is characterized by an extensive production history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. We report operations in two operating segments: (i) the upstream segment and (ii) the midstream operations segment, which includes midstream services and real estate operations.

Our activities are primarily focused on horizontal development of the Spraberry and Wolfcamp formations of the Midland Basin and the Wolfcamp and Bone Spring formations of the Delaware Basin, both of which are part of the larger Permian Basin in West Texas and New Mexico. These formations are characterized by a high concentration of oil and liquids rich natural gas, multiple vertical and horizontal target horizons, extensive production history, long-lived reserves and high drilling success rates.

At December 31, 2020, our total acreage position in the Permian Basin was approximately 449,642 gross (378,678 net) acres, which consisted primarily of approximately 215,956 gross (194,591 net) acres in the Midland Basin and approximately 192,697 gross (152,587 net) acres in the Delaware Basin.

In addition, our publicly traded subsidiary Viper Energy Partners LP, which we refer to as Viper, owns mineral interests in the Permian Basin and Eagle Ford Shale. We own Viper Energy Partners GP LLC, the general partner of Viper, which we refer to as Viper's general partner, and we own approximately 58% of the limited partner interest in Viper.

Further, our publicly traded subsidiary Rattler Midstream Partners LP, which we refer to as Rattler, is focused on ownership, operation, development and acquisition of midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. We own Rattler Midstream GP LLC, the general partner of Rattler, which we refer to as Rattler's general partner, and we own approximately 72% of the limited partner interest in Rattler.

As of December 31, 2020, our estimated proved oil and natural gas reserves were 1,316,441 MBOE (which includes estimated reserves of 99,392 MBOE attributable to the mineral interests owned by Viper). Of these reserves, approximately 62% are classified as proved developed producing. Proved undeveloped, or PUD, reserves included in this estimate are from 628 gross (559 net) horizontal well locations in which we have a working interest, and 38 horizontal wells in which we own only a mineral interest through our subsidiary, Viper. As of December 31, 2020, our estimated proved reserves were approximately 58% oil, 22% natural gas liquids and 20% natural gas.

Pending Merger with QEP Resources, Inc.

On December 20, 2020, we, QEP Resources, Inc., or QEP, and Bohemia Merger Sub, Inc., our wholly owned subsidiary, or the Merger Sub, entered into an Agreement and Plan of Merger, which is referred to as the merger agreement, under which Merger Sub will be merged with and into QEP, with QEP surviving as our wholly owned subsidiary, which we refer to as the pending merger. If the pending merger is completed, each QEP stockholder will receive, in exchange for each share of QEP common stock held immediately prior to the closing of the pending merger, 0.050 of a share of our common stock.

The completion of the pending merger is subject to satisfaction or waiver of certain customary mutual closing conditions, including (a) the receipt of the required approvals from QEP's stockholders, (b) the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, or the HSR Act, (c) the absence of any governmental order or law that makes consummation of the pending merger illegal or otherwise prohibited, (d) the effectiveness of the registration statement on Form S-4 relating to the shares of our common stock to be issued in connection with the pending merger, which registration statement was declared effective by the SEC on February 10, 2021, and (e) the authorization for listing of such common stock on the Nasdaq Global Select Market. The obligation of each party to consummate the pending merger is also conditioned upon the other party's representations and warranties being true and correct (subject to certain materiality exceptions), the other party having performed in all material respects its obligations under the merger agreement, and the receipt of an officer's certificate from the other party to such effect. For additional information regarding the pending merger and our expectations relating to the combined company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Pending Guidon Acquisition

On December 18, 2020, we and Diamondback E&P LLC, our wholly owned subsidiary, entered into a definitive, purchase and sale agreement with Guidon Operating LLC, or Guidon, and certain of Guidon's affiliates to acquire approximately 32,500 net acres in the Northern Midland Basin and certain related oil and natural gas assets, which we refer to as the Pending Guidon Acquisition. Consideration for the Pending Guidon Acquisition consists of $375 million in cash and 10.6 million shares of our common stock, subject to adjustment. The Pending Guidon Acquisition is expected to close on February 26, 2021.

COVID-19

On March 11, 2020, the World Health Organization characterized the global outbreak of the novel strain of coronavirus, COVID-19, as a "pandemic." To limit the spread of COVID-19, governments have taken various actions including the issuance of stay-at-home orders and social distancing guidelines, causing some businesses to suspend operations and a reduction in demand for many products from direct or ultimate customers. Although many stay-at-home orders have expired and certain restrictions on conducting business have been lifted, the COVID-19 pandemic resulted in a widespread health crisis and a swift and unprecedented reduction in international and U.S. economic activity which, in turn, has adversely affected the demand for oil and natural gas and caused significant volatility and disruption of the financial markets.

In early March 2020, oil prices dropped sharply, and then continued to decline reaching negative levels. During 2020, the average NYMEX WTI futures contract price for crude oil and condensate was $39.34 per barrel and the average Henry Hub futures contract price for natural gas was $2.13 per million British thermal units (MMBtu), representing decreases of 31% and 16%, respectively, from the comparable average futures prices during 2019. These decreases were the result of multiple factors affecting supply and demand in global oil and natural gas markets, including actions taken by OPEC members and other exporting nations impacting commodity price and production levels and a significant decrease in demand due to the ongoing COVID-19 pandemic. While OPEC members and certain other nations agreed in April 2020 to cut production and subsequently extended such production cuts through December 2020, which helped to reduce a portion of the excess supply in the market and improve crude oil prices, they agreed to increase production by 500,000 barrels per day beginning in January 2021. We cannot predict if or when commodity prices will stabilize and at what levels.

As a result of the reduction in crude oil demand caused by factors discussed above, in 2020, we lowered our 2020 capital budget and production guidance, curtailed near term production and reduced rig count, all of which may be subject to further reductions or curtailment if the commodity markets and macroeconomic conditions worsen. Although we have restored curtailed production, actions taken in response to the COVID-19 pandemic and depressed commodity pricing environment have had and are expected to continue to have an adverse effect on our business, financial results and cash flows. For additional details, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Overview."

Given the dynamic nature of the events described above, we cannot reasonably estimate the period of time that the ongoing COVID-19 pandemic, the depressed commodity prices, the reduced demand for oil and the adverse macroeconomic conditions will persist, the full extent of the impact they will have on our industry and our business, financial condition, results of operations or cash flows, or the pace or extent of any subsequent recovery.

Our Business Strategy

Our business strategy is to continue to profitably grow our business through the following:

- **Grow production and reserves by developing our oil-rich resource base.** We intend to drill and develop our acreage base in an effort to maximize its value and resource potential. Through the conversion of our undeveloped reserves to developed reserves, we will seek to increase our production, reserves and cash flow while generating favorable returns on invested capital.

- **Leverage our experience operating in the Permian Basin.** Our executive team, which has an average of over 25 years of industry experience per person and significant experience in the Permian Basin, intends to continue to seek ways to maximize hydrocarbon recovery by refining and enhancing our drilling and completion techniques. Our focus on efficient drilling and completion techniques is an important part of the continuous drilling program we have planned for our significant inventory of identified potential drilling locations. We believe that the experience of our executive team in deviated and horizontal drilling and completions has helped reduce the execution risk normally associated with these complex well paths. In addition, our completion techniques are continually evolving as we evaluate and implement hydraulic fracturing practices that have and are expected to continue to increase recovery and reduce completion costs. Our executive team regularly evaluates our operating results against those of other operators in the area in an effort to benchmark our performance against the best performing operators and evaluate and adopt best practices.

- **Enhance returns through our low cost development strategy and focus on continuous improvement in operational, capital allocation and cost efficiencies.** Our acreage position is generally in contiguous blocks which allows us to develop this acreage efficiently with a "manufacturing" strategy that takes advantage of economies of scale and uses centralized production and fluid handling facilities. We are the operator of approximately 98% of our acreage. This operational control allows us to manage more efficiently the pace of development activities and the gathering and marketing of our production and control operating costs and technical applications, including horizontal development. Our average 84% working interest in our acreage allows us to realize the majority of the benefits of these activities and cost efficiencies.

- **Pursue strategic acquisitions with substantial resource potential.** We have a proven history of acquiring leasehold positions in the Permian Basin that have substantial oil-weighted resource potential. Our executive team, with its extensive experience in the Permian Basin, has what we believe is a competitive advantage in identifying acquisition targets and a proven ability to evaluate resource potential. Most recently, in December 2020, we entered into the merger agreement with QEP to acquire QEP in an all-stock transaction valued at approximately $2.2 billion, including QEP's net debt of $1.6 billion as of September 30, 2020. The pending merger, upon closing, will add material Tier-1 Midland Basin inventory. In December 2020, we also entered into a definitive purchase and sale agreement with Guidon and certain of Guidon's affiliates to acquire approximately 32,500 net acres in the Northern Midland Basin and certain related oil and natural gas assets. We regularly review acquisition opportunities and intend to pursue acquisitions that meet our strategic and financial targets.

- **Maintain financial flexibility.** We seek to maintain a conservative financial position. As of December 31, 2020, our borrowing base was set at $2.0 billion and we had $1.98 billion available for borrowing. As of December 31, 2020, Viper LLC had $84 million in outstanding borrowings, and $496 million available for borrowing, under its revolving credit facility. As of December 31, 2020, Rattler LLC had $79 million in outstanding borrowings, and $521 million available for borrowing, under its revolving credit facility.

Our Strengths

We believe that the following strengths will help us achieve our business goals:

- **Oil rich resource base in one of North America's leading resource plays.** All of our leasehold acreage is located in one of the most prolific oil plays in North America, the Permian Basin in West Texas. The majority of our current properties are well positioned in the core of the Permian Basin. Our production for the year ended December 31, 2020 was approximately 60% oil, 20% natural gas liquids and 20% natural gas. As of December 31, 2020, our estimated net proved reserves were comprised of approximately 58% oil, 22% natural gas liquids and 20% natural gas.

- **Multi-year drilling inventory in one of North America's leading oil resource plays.** We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. At an assumed price of approximately $60.00 per Bbl WTI, we currently have approximately 10,413 gross (6,863 net) identified economic potential horizontal drilling locations on our acreage based on our evaluation of applicable geologic and engineering data. These gross identified economic potential horizontal locations have an average lateral length of approximately 8,200 feet, with the actual length depending on lease geometry and other considerations. These locations exist across most of our acreage blocks and in multiple horizons. The ultimate inter-well spacing may vary from these distances due to different factors, which would result in a higher or lower location count. In addition, we have approximately 3,610 square miles of proprietary 3-D seismic data covering our acreage. This data facilitates the evaluation of our existing drilling inventory and provides insight into future development activity, including additional horizontal drilling opportunities and strategic leasehold acquisitions.

- **Experienced, incentivized and proven management team.** Our executive team has a proven track record of executing on multi-rig development drilling programs and extensive experience in the Permian Basin. In addition, our executive team has significant experience with both drilling and completing horizontal wells in addition to horizontal well reservoir and geologic expertise, which is of strategic importance as we expand our horizontal drilling activity.

- **Favorable operating environment.** We have focused our drilling and development operations in the Permian Basin, one of the longest operating hydrocarbon basins in the United States, with a long and well-established production history and developed infrastructure. We believe that the geological and regulatory environment of the Permian Basin is more stable and predictable, and that we are faced with less operational risks in the Permian Basin as compared to emerging hydrocarbon basins.

- **High degree of operational control.** We are the operator of approximately 98% of our Permian Basin acreage. This operating control allows us to better execute on our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery by seeking to continually improve our drilling techniques, completion methodologies and reservoir evaluation processes. Additionally, as the operator of substantially all of our acreage, we retain the ability to increase or decrease our capital expenditure program based on commodity price outlooks. This operating control also enables us to obtain data needed for efficient exploration of horizontal prospects.

- **Access to midstream infrastructure and gathering and transportation pipelines**. Through our publicly traded subsidiary Rattler, we have secured access to midstream infrastructure and crude oil gathering and transportation pipelines tailored to our expected production growth ramp in order to allow us the operational flexibility to execute on our growth plan. Rattler is the primary provider of midstream services to us with an acreage dedication that spans a total of approximately 395,000 gross acres across all of Rattler's service lines and over the core of the Midland and Delaware Basins.

Our Properties

Location and Land

The Permian Basin area covers a significant portion of western Texas and eastern New Mexico and is considered one of the major producing basins in the United States. As of December 31, 2020, our total acreage position in the Permian Basin was approximately 449,642 gross (378,678 net) acres, which consisted primarily of approximately 215,956 gross (194,591 net) acres in the Midland Basin and approximately 192,697 gross (152,587 net) acres in the Delaware Basin. We are the operator of approximately 98% of this Permian Basin acreage. In addition, our publicly traded subsidiary Viper owns mineral interests underlying approximately 787,264 gross acres and 24,350 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 52% of these net royalty acres are operated by us.

We have been developing multiple pay intervals in the Permian Basin through horizontal drilling and believe that there are opportunities to target additional intervals throughout the stratigraphic column. We believe our significant experience drilling, completing and operating horizontal wells will allow us to efficiently develop our remaining inventory and ultimately target other horizons that have limited development to date. The following table presents horizontal producing wells in which we have a working interest in as of December 31, 2020:

Basin	Number of Horizontal Wells
Midland	1,408
Delaware	917
Other	55
Total(1)	2,380

(1) Of these 2,380 total horizontal producing wells, we are the operator of 1,694 wells and have a non-operated working interest in 686 additional wells.

The following table presents the average number of days in which we were able to drill our horizontal wells to total depth specified below during the year ended December 31, 2020:

	Average Days to Total Depth
Midland Basin	
7,500 foot lateral	12
10,000 foot lateral	13
13,000 foot lateral	17
Delaware Basin	
7,500 foot lateral	16
10,000 foot lateral	18
13,000 foot lateral	26

Further advances in drilling and completion technology may result in economic development of zones that are not currently viable.

Further, our subsidiary Rattler is focused on ownership, operation, development and acquisition of the midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. As of December 31, 2020, Rattler owned and operated 927 miles of crude oil gathering pipelines, natural gas gathering pipelines and a fully integrated water system on acreage that overlays our seven core Midland and Delaware Basin development areas. To facilitate the transportation of water and hydrocarbon volumes away from the producing wellhead to ensuring the efficient operations of a crude oil or natural gas well, Rattler's midstream infrastructure includes a network of gathering pipelines that collect and transport crude oil, natural gas and produced water from our operations in the Midland and Delaware Basins.

As of December 31, 2020, Rattler also owned (i) a 10% equity interest in EPIC Crude Holdings LP, which owns and operates a long-haul crude oil pipeline from the Permian Basin and the Eagle Ford Shale to Corpus Christi, Texas that is capable of transporting approximately 600,000 Bbl/d, which began full operations in April 2020 and is referred to as the EPIC pipeline, (ii) a 10% equity interest in Gray Oak Pipeline, LLC, which owns and operates a long-haul crude oil pipeline that is capable of transporting 900,000 Bbl/d from the Permian Basin and the Eagle Ford Shale to points alongside the Texas Gulf Coast, including a marine terminal connection in Corpus Christi, Texas, which began full operations in April 2020 and is referred to as the Gray Oak pipeline, (iii) a 4% equity interest in Wink to Webster Pipeline LLC, which is developing a crude oil pipeline that upon full commercial operations expected in the fourth quarter of 2021 will be capable of transporting approximately 1,500,000 Bbl/d from origin points at Wink and Midland in the Permian Basin for delivery to multiple Houston area locations, (iv) a 60% equity interest in OMOG JV LLC, which operates approximately 235 miles of crude oil gathering and regional transportation pipelines and approximately 200,000 barrels of crude oil storage in Midland, Martin, Andrews and Ector Counties, Texas and (v) a 50% equity interest in Amarillo Rattler LLC, which owns and operates the Yellow Rose gas gathering and processing system with estimated total capacity of 40,000 Mcf/d and over 84 miles of gathering and regional transportation pipelines in Dawson, Martin and Andrews Counties, Texas. For additional information regarding our equity method investments as of December 31, 2020, see Note 10—Equity Method Investments to our consolidated financial statements included elsewhere in this Annual Report.

Rattler also owns and operates certain real estate assets in Midland, Texas including the Fasken Center which has over 421,000 net rentable square feet within its two office towers.

Area History

Our proved reserves are located in the Permian Basin of West Texas, in particular in the Clearfork, Spraberry, Bone Spring, Wolfcamp, Strawn, Atoka and Barnett formations. The Spraberry play was initiated with production from several new field discoveries in the late 1940s and early 1950s. It was eventually recognized that a regional productive trend was present, as fields were extended and coalesced over a broad area in the central Midland Basin. Development in the Spraberry play was sporadic over the next several decades due to typically low productive rate wells, with economics being dependent on oil prices and drilling costs.

The Wolfcamp formation is a long-established reservoir in West Texas, first found in the 1950s as wells aiming for deeper targets occasionally intersected slump blocks or debris flows with good reservoir properties. Exploration using 2-D seismic data located additional fields, but it was not until the use of 3-D seismic data in the 1990s that the greater extent of the Wolfcamp formation was revealed. The additional potential of the shales within this formation as reservoir rather than just source rocks was not recognized until very recently.

By mid-2010, approximately half of the rigs active in the Permian Basin were drilling wells in the Permian Spraberry, Dean and Wolfcamp formations, which we collectively refer to as the Wolfberry play. Since then we and most other operators are almost exclusively drilling horizontal wells in the development of unconventional reservoirs in the Permian Basin. As of December 31, 2020, we held working interests in 4,326 gross (3,401 net) producing wells and only royalty interests in 4,553 additional wells.

Geology

The Greater Permian Basin formed as an area of rapid Pennsylvanian-Permian subsidence in response to dynamic structural influence of the Marathon Uplift and Ancestral Rockies. It is one of the most productive sedimentary basins in the U.S., with established oil and natural gas production from several stacked reservoirs of varying age ranges, most notably Permian aged sediments. In particular, the Permian aged Wolfcamp, Spraberry and Bone Spring Formations have been heavily targeted for several decades. First, through vertical comingling of these zones and, more recently, through horizontal exploitation of each individual horizon. Prior to deposition of the Wolfcamp, Spraberry and Bone Spring Formations, the area of the present-day Permian Basin was a continuous sedimentary feature called the Tabosa Basin. During this time, Ordovician, Silurian, Devonian and Mississippian sediments were laid down in a primarily open marine, shelf setting. However, some time frames saw more restrictive settings that were conducive to the deposition of organically rich mudstone such as the Devonian Woodford and Mississippian Barnett/Meramec. These formations are important sources and, more recently, reservoirs within the present-day Greater Permian Basin.

The Spraberry and Bone Spring Formations were deposited as siliciclastic and carbonate turbidites and debris flows along with pelagic mudstones in a deep-water, basinal environment, while the Wolfcamp reservoirs consist of debris-flow, grain-flow and fine-grained pelagic sediments, which were also deposited in a basinal setting. The best carbonate reservoirs within the Wolfcamp, Spraberry and Bone Spring are generally found in close proximity to the Central Basin Platform, while mudstone reservoirs thicken basin-ward, away from the Central Basin Platform. The mudstone within these reservoirs is organically rich, which when buried to sufficient depth for thermal maturation, became the source of the hydrocarbons found both within the mudstones themselves and in the interbedded conventional clastic and carbonate reservoirs. Due to this complexity, the Wolfcamp, Spraberry and Bone Spring intervals are a hybrid reservoir system that contains characteristics of both unconventional and conventional reservoirs.

We have successfully developed several hybrid reservoir intervals within the Clearfork, Spraberry/Bone Spring, Wolfcamp and Barnett/Meramec formations since we began horizontal drilling in 2012. The mudstones and some clastics exhibit low permeabilities which necessitate the need for hydraulic fracture stimulation to unlock the vast storage of hydrocarbons in these targets.

We possess, or are in the process of acquiring, 3-D seismic data over substantially all of our major asset areas. Our extensive geophysical database currently includes approximately 3,610 square miles of 3-D data. This data will continue to be utilized in the development of our horizontal drilling program and identification of additional resources to be exploited.

Production Status

During the year ended December 31, 2020, net production from our acreage was 109,921 MBOE, or an average of 300,331 BOE/d, of which approximately 60% was oil, 20% was natural gas liquids and 20% was natural gas.

Recent and Future Activity

During 2021, we expect to complete an estimated 215 to 235 gross (197 to 215 net) operated horizontal wells on our acreage. We currently estimate that our capital expenditures in 2021 for drilling and infrastructure will be between \$1.4 billion and \$1.6 billion, consisting of \$1.2 billion to \$1.4 billion for horizontal drilling and completions including non-operated activity, \$60 million to \$80 million for midstream investments, excluding joint venture investments, and \$70 million to \$90 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions. During the year ended December 31, 2020, we drilled 208 gross (195 net) and completed 171 gross (159 net) operated horizontal wells. During the year ended December 31, 2020, our capital expenditures for drilling, completing and equipping wells were \$1.6 billion. In addition, we spent \$248 million for oil and natural gas midstream and infrastructure.

We were operating eight drilling rigs at December 31, 2020 and currently intend to operate between eight and 12 rigs on average in 2021. We will continue monitoring the ongoing commodity price environment and expect to retain the financial flexibility to adjust our drilling and completion plans in response to market conditions.

Based on our evaluation of applicable geologic and engineering data, we currently have approximately 10,413 gross (6,863 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage at an assumed price of approximately $60.00 per Bbl WTI. With our current development plan, we expect to continue our strong PUD conversion ratio in 2021 by converting an estimated 30% of our PUDs to a proved developed category and developing approximately 80% of the consolidated 2020 year-end PUD reserves by the end of 2023.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Reserves

Our historical reserve estimates as of December 31, 2020, 2019 and 2018 were prepared by Ryder Scott with respect to our assets and those of Viper. Ryder Scott is an independent petroleum engineering firm. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott is a third-party engineering firm and does not own an interest in any of our properties and is not employed by us on a contingent basis.

Under SEC rules, proved reserves are those quantities of oil and natural gas that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a “high degree of confidence that the quantities will be recovered.” All of our proved reserves as of December 31, 2020 were estimated using a deterministic method.

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Approximately 90% of the proved producing reserves attributable to producing wells were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of available historical production and pressure data. The remaining 10% of the proved producing reserves were estimated by analogy, or a combination of performance and analogy methods. The analogy method was used where there were inadequate historical performance data to establish a definitive trend and where the use of production performance data as a basis for the reserve estimates was considered to be inappropriate. All proved developed non-producing and undeveloped reserves were estimated by the analogy method.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves included production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

The process of estimating oil, natural gas and natural gas liquids reserves is complex and requires significant judgment, as discussed in “Item 1A. Risk Factors” of this report. As a result, we maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members met with our independent reserve engineers periodically during the period covered by the reserve reports to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

Our Executive Vice President–Chief Engineer is primarily responsible for overseeing the preparation of all our reserve estimates. Our Executive Vice President–Chief Engineer is a petroleum engineer with over 30 years of reservoir and operations experience and our geoscience staff has an average of approximately 20 years of industry experience per person. Our technical staff uses historical information for our properties such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

The preparation of our proved reserve estimates is completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our Executive Vice President–Chief Engineer or under his direct supervision;
- review by our Executive Vice President–Chief Engineer of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions;
- direct reporting responsibilities by our Executive Vice President–Chief Engineer to our Chief Executive Officer;
- verification of property ownership by our land department; and
- no employee's compensation is tied to the amount of reserves booked.

The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2020, 2019 and 2018 (including those attributable to Viper), based on the reserve reports prepared by Ryder Scott in accordance with the rules and regulations of the SEC. All of our proved reserves included in the reserve reports are located in the continental United States. As of December 31, 2020, none of our total proved reserves were classified as proved developed non-producing.

	As of December 31,		
	2020	**2019**	**2018**
Estimated Proved Developed Reserves:			
Oil (MBbls)	443,464	457,083	403,051
Natural gas (MMcf)	1,085,035	824,760	705,084
Natural gas liquids (MBbls)	192,495	165,173	125,509
Total (MBOE)	816,798	759,716	646,074
Estimated Proved Undeveloped Reserves:			
Oil (MBbls)	315,937	253,820	223,885
Natural gas (MMcf)	522,029	294,051	343,565
Natural gas liquids (MBbls)	96,701	65,030	64,782
Total (MBOE)	499,643	367,859	345,928
Estimated Net Proved Reserves:			
Oil (MBbls)	759,401	710,903	626,936
Natural gas (MMcf)	1,607,064	1,118,811	1,048,649
Natural gas liquids (MBbls)	289,196	230,203	190,291
Total (MBOE)(1)	1,316,441	1,127,575	992,001
Percent proved developed	62%	67%	65%

(1) Estimates of reserves as of December 31, 2020, 2019 and 2018 were prepared using an average price equal to the unweighted arithmetic average of hydrocarbon prices received on a field-by-field basis on the first day of each month within the 12-month periods ended December 31, 2020, 2019 and 2018, respectively, in accordance with SEC guidelines. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for undeveloped acreage. The reserve estimates represent our net revenue interest in our properties, all of which are located within the continental United States. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates. See "Item 1A. Risk Factors" for a discussion of risks and uncertainties associated with our estimates of proved reserves and related factors, and see Note 20—Supplemental Information on Oil and Natural Gas Operations for further discussion of our reserve estimates and pricing.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2020, our proved undeveloped reserves totaled 315,937 MBbls of oil, 522,029 MMcf of natural gas and 96,701 MBbls of natural gas liquids, for a total of 499,643 MBOE. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table includes the changes in PUD reserves for 2020 (MBOE):

Beginning proved undeveloped reserves at December 31, 2019	367,859
Undeveloped reserves transferred to developed	(89,133)
Revisions	(15,742)
Purchases	964
Divestitures	(14)
Extensions and discoveries	235,709
Ending proved undeveloped reserves at December 31, 2020	499,643

The increase in proved undeveloped reserves was primarily attributable to extensions of 220,023 MBOE from 277 gross (236 net) wells in which we have a working interest and 15,686 MBOE from 299 gross wells in which Viper owns royalty interests. Of the 277 gross working interest wells, 98 were in the Delaware Basin. Transfers of 89,133 MBOE from undeveloped to developed reserves were the result of drilling or participating in 102 gross (94 net) horizontal wells in which we have a working interest and 82 gross wells in which we have a royalty interest or mineral interest through Viper. We own a working interest in 78 of the 82 gross Viper wells. Downward revisions of 15,742 MBOE were the result of (i) negative revisions of 4,226 MBOE due to lower product pricing, which were partially offset by positive revisions of 1,494 MBoe associated with a reduction in lease operating expenses, resulting in a total negative pricing revision of 2,732 MBOE, and (ii) PUD downgrades of 26,329 MBOE are primarily from changes in the corporate development plan. These negative revisions were offset with positive revisions of 13,319 MBOE associated with less gas flaring and a corresponding increase in shrunk gas and natural gas liquid recoveries.

Costs incurred relating to the development of PUDs were approximately $381 million during 2020. Estimated future development costs relating to the development of PUDs are projected to be approximately $676 million in 2021, $764 million in 2022, $859 million in 2023 and $531 million in 2024. Since our formation in 2011, our average drilling costs and drilling times have been reduced, and we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years.

As of December 31, 2020, all of our proved undeveloped reserves are scheduled to be developed within five years from the date they were initially recorded.

We have identified a multi-year inventory of potential drilling locations for our oil-weighted reserves that we believe provides attractive growth and return opportunities. At an assumed price of approximately $60.00 per Bbl WTI, we currently have approximately 10,413 gross (6,863 net) identified economic potential horizontal drilling locations on our acreage based on our evaluation of applicable geologic and engineering data. The following table presents the number of identified economic potential horizontal drilling locations by basin:

	Number of Identified Economic Potential Horizontal Drilling Locations
Midland Basin	
Lower Spraberry(1)	1,015
Middle Spraberry(2)	1,074
Wolfcamp A(3)	909
Wolfcamp B(3)	1,006
Other	2,111
Total Midland Basin	6,115
Delaware Basin	
2nd Bone Springs(4)	870
3rd Bone Springs(4)	1,222
Wolfcamp A(5)	854
Wolfcamp B(6)	755
Other	597
Total Delaware Basin	4,298
Total	10,413

(1) Our current location count is based on 660 foot to 880 foot spacing in Midland, Martin, northeast Andrews, Howard and Glasscock counties, depending on the prospect area and 880 foot spacing in all other counties.
(2) Our current location count is based on 660 foot spacing in Midland, Martin and northeast Andrews counties, depending on the prospect area and 880 foot spacing in all other counties.
(3) Our current location count is based on 660 foot to 880 foot spacing in Midland, Martin, northeast Andrews, Howard and Glasscock counties, depending on the prospect area and 880 foot spacing in all other counties.
(4) Our current location count is based on 880 foot to 1,320 foot spacing.
(5) Our current location count is based on 880 foot to 1,056 foot spacing.

Oil and Natural Gas Production Prices and Production Costs

Production and Price History

The following tables set forth information regarding our net production of oil, natural gas and natural gas liquids by basin for each of the periods indicated:

	Midland Basin	Delaware Basin	Other(1)(2)	Total
		(in thousands)		
Production Data:				
Year Ended December 31, 2020				
Oil (MBbls)	38,313	27,703	166	66,182
Natural gas (MMcf)	68,529	61,606	414	130,549
Natural gas liquids (MBbls)	12,597	9,295	89	21,981
Total (MBoe)	62,332	47,266	324	109,921
Year Ended December 31, 2019				
Oil (MBbls)	41,156	25,951	1,411	68,518
Natural gas (MMcf)	48,109	48,447	1,057	97,613
Natural gas liquids (MBbls)	10,485	7,826	187	18,498
Total (MBoe)	59,659	41,852	1,774	103,285
Year Ended December 31, 2018				
Oil (MBbls)	24,698	9,288	381	34,367
Natural gas (MMcf)	21,674	12,416	579	34,669
Natural gas liquids (MBbls)	5,493	1,866	106	7,465
Total (MBoe)	33,803	13,223	584	47,610

(1) Production data for the years ended December 31, 2020 and 2019 includes the Central Basin Platform, the Eagle Ford Shale and the Rockies.
(2) Production data for the year ended December 31, 2018 includes the Eagle Ford Shale.

The following table sets forth certain price and cost information for each of the periods indicated:

	Year Ended December 31,		
	2020	2019	2018
Average Prices:			
Oil ($ per Bbl)	$ 36.41	$ 51.87	$ 54.66
Natural gas ($ per Mcf)	$ 0.82	$ 0.68	$ 1.76
Natural gas liquids ($ per Bbl)	$ 10.87	$ 14.42	$ 25.47
Combined ($ per BOE)	$ 25.07	$ 37.63	$ 44.73
Oil, hedged ($ per Bbl)(1)	$ 40.34	$ 51.96	$ 51.20
Natural gas, hedged ($ per MMbtu)(1)	$ 0.67	$ 0.86	$ 1.72
Natural gas liquids, hedged ($ per Bbl)(1)	$ 10.83	$ 15.20	$ 25.46
Average price, hedged ($ per BOE)(1)	$ 27.26	$ 38.00	$ 42.20
Average Costs per BOE:			
Lease operating expenses	$ 3.87	$ 4.74	$ 4.31
Production and ad valorem taxes	1.77	2.40	2.79
Gathering and transportation expense	1.27	0.86	0.55
General and administrative - cash component	0.46	0.54	0.79
Total operating expense - cash	$ 7.37	$ 8.54	$ 8.44
General and administrative - non-cash component	$ 0.34	$ 0.46	$ 0.57
Depletion	11.30	13.54	12.50
Interest expense, net	1.79	1.66	1.83
Merger and integration expense	—	—	0.77
Total expenses	$ 13.43	$ 15.66	$ 15.67

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

Wells Drilled and Completed in 2020

The following table sets forth the total number of operated horizontal wells drilled and completed during the year ended December 31, 2020:

	Year Ended December 31, 2020			
	Drilled		Completed	
Area	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	133	125	93	85
Delaware Basin	75	70	78	74
Total	208	195	171	159

As of December 31, 2020, we operated the following wells:

	Vertical Wells		Horizontal Wells		Total	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	1,745	1,641	1,102	1,008	2,847	2,649
Delaware Basin	25	22	592	557	617	579
Total	1,770	1,663	1,694	1,565	3,464	3,228

Productive Wells

As of December 31, 2020, we owned an average unweighted 79% working interest in 4,326 gross (3,401 net) productive wells and an average 1.8% royalty interest in 4,553 additional wells. Through our subsidiary Viper, we own an average 3.8% net revenue interest in 7,167 gross productive wells. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

The following table sets forth information regarding productive wells by basin as of December 31, 2020:

	Gross Wells			Net Wells		
	Oil	**Natural Gas**	**Total**	**Oil**	**Natural Gas**	**Total**
Midland Basin	5,397	29	5,426	2,740	10	2,750
Delaware Basin	1,904	158	2,062	630	19	649
Other	1,316	75	1,391	2	—	2
Total productive wells	8,617	262	8,879	3,372	29	3,401

Drilling Results

The following tables set forth information with respect to the number of wells completed during the periods indicated by basin. Each of these wells was drilled in the Permian Basin of West Texas. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Year Ended December 31, 2020					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	87	81	26	25	113	106
Dry	—	—	—	—	—	—
Exploratory:						
Productive	46	44	49	45	95	89
Dry	—	—	—	—	—	—
Total:						
Productive	133	125	75	70	208	195
Dry	—	—	—	—	—	—

	Year Ended December 31, 2019					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	75	68	31	28	106	96
Dry	—	—	—	—	—	—
Exploratory:						
Productive	96	86	128	114	224	200
Dry	—	—	—	—	—	—
Total:						
Productive	171	154	159	142	330	296
Dry	—	—	—	—	—	—

	Year Ended December 31, 2018					
	Midland Basin		Delaware Basin		Total	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	67	58	21	20	88	78
Dry	—	—	—	—	—	—
Exploratory:						
Productive	50	43	38	35	88	78
Dry	—	—	—	—	—	—
Total:						
Productive	117	101	59	55	176	156
Dry	—	—	—	—	—	—

As of December 31, 2020, we had 20 gross (19 net) operated wells in the process of drilling and 151 gross (141 net) in the process of completion or waiting on completion.

Acreage

The following table sets forth information as of December 31, 2020 relating to our leasehold acreage:

	Developed Acreage(1)		Undeveloped Acreage		Total Acreage(2)	
Basin	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland	119,073	99,751	96,883	94,840	215,956	194,591
Delaware	103,712	77,263	88,985	75,324	192,697	152,587
Exploration	107	107	38,097	28,838	38,204	28,945
Conventional Permian	40	38	2,745	2,517	2,785	2,555
Total	222,932	177,159	226,710	201,519	449,642	378,678

(1) Does not include undrilled acreage held by production under the terms of the lease. Large portions of the acreage that are considered developed under SEC guidelines are developed with vertical wells or horizontal wells that are in a single horizon. We believe much of this acreage has significant remaining development potential in one or more intervals with horizontal wells.
(2) Does not include Viper's mineral interests but does include leasehold acres that we own underlying our mineral interests.

Undeveloped acreage expirations

As of December 31, 2020, the following gross and net undeveloped acres are set to expire over the next four years based on their contractual lease maturities unless (i) production is established within the spacing units covering the acreage or (ii) the lease is renewed or extended under continuous drilling provisions prior to the contractual expiration dates.

	Acres Expiring							
	Delaware		**Midland**		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
2021	13,727	8,149	24,099	21,093	23,474	22,063	61,300	51,305
2022	9,634	1,063	3,294	813	659	165	13,587	2,041
2023	966	410	1,951	1,597	—	—	2,917	2,007
2024	370	59	—	—	—	—	370	59
Total	24,697	9,681	29,344	23,503	24,133	22,228	78,174	55,412

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

Marketing and Customers

We typically sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2020, four purchasers each accounted for more than 10% of our revenue. For each of the years ended December 31, 2019 and 2018, three purchasers each accounted for more than 10% of our revenue. We do not require collateral and do not believe the loss of any single purchaser would materially impact our operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers. For additional information regarding our customer concentrations, see Note 3—Revenue from Contracts with Customers included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Delivery Commitments

Certain of our firm sales agreements for oil include delivery commitments that specify the delivery of a fixed and determinable quantity. We believe our current production and reserves are sufficient to fulfill these delivery commitments and we expect such reserves will continue to be the primary means of fulfilling our future commitments. However, these contracts provide the options of delivering third-party volumes or paying a monetary shortfall penalty if production is inadequate to satisfy our commitment. For additional information regarding commitments, see Note 17—Commitments and Contingencies included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Competition

The oil and natural gas industry is intensely competitive, and in our upstream segment, we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. Further, oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

In our midstream operations segment, as Rattler seeks to expand its crude oil, natural gas and water-related midstream services, it faces a high level of competition, including major integrated crude oil and natural gas companies, interstate and intrastate pipelines and companies that gather, compress, treat, process, transport, store or market oil and natural gas. As Rattler seeks to expand to provide midstream services to third party producers, it similarly faces a high level of competition. Competition is often the greatest in geographic areas experiencing robust drilling by producers and during periods of high commodity prices for crude oil, natural gas or natural gas liquids. Within the acreage dedicated by Rattler to us, Rattler does not compete with other midstream companies to provide us with midstream services as a result of our relationship and long-term dedications to Rattler’s midstream assets. However, we may continue to use third party service providers for certain midstream services within such dedicated acreage until the expiration or termination of certain pre-existing dedications.

Transportation

During the initial development of our fields we evaluate all gathering and delivery infrastructure in the areas of our production. Currently, a majority of our production in the Midland and Delaware Basins are transported to purchasers by pipeline.

The following table presents the average percentage of produced oil sold by pipeline and the average percentage of produced water connected to saltwater disposals by pipeline:

	Midland Basin	Delaware Basin	Total
% of produced oil sold by pipeline	95 %	93 %	94 %
% of produced water transported by pipeline	97 %	98 %	98 %

We have entered into multiple fee-based commercial agreements with Rattler, each with an initial term ending in 2034, utilizing Rattler’s infrastructure assets or its planned infrastructure assets to provide an array of essential services critical to our upstream operations in the Delaware and Midland Basins. Our agreements with Rattler include a total of approximately 395,000 gross acres across all Rattler’s service lines across the Midland and Delaware Basins.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 12.5% to 30.0%, resulting in a net revenue interest to us generally ranging from 70.0% to 87.5%.

Seasonal Nature of Business

Generally, demand for oil increases during the summer months and decreases during the winter months while natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. In our exploration and production business, seasonal weather conditions, such as, for example, the recent severe winter storms in the Permian Basin, and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in a portion of our operating areas. These seasonal anomalies can pose challenges for meeting our well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay operations. In our midstream operations business, the volumes of condensate produced at Rattler's processing facilities fluctuate seasonally, with volumes generally increasing in the winter months and decreasing in the summer months as a result of the physical properties of natural gas and comingled liquids. Severe or prolonged summers may adversely affect our results of operations in the midstream operations segment.

Regulation

Oil and natural gas operations such as ours are subject to various types of legislation, regulation and other legal requirements enacted by governmental authorities. This legislation and regulation affecting the oil and natural gas industry is under constant review for amendment or expansion. Some of these requirements carry substantial penalties for failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability.

Environmental Matters and Regulation

Our oil and natural gas exploration, development and production operations are subject to stringent laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous federal, state and local governmental agencies, such as the EPA, issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or related to our owned or operated facilities. Liability under such laws and regulations is often strict (i.e., no showing of "fault" is required) and can be joint and several. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Waste Handling. The Resource Conservation and Recovery Act, or the RCRA, as amended, and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of the RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under the RCRA, such wastes may constitute "solid wastes" that are subject to the less stringent non-hazardous waste requirements. Moreover, the EPA or state or local governments may adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as “hazardous wastes.” Also, in December 2016, the EPA agreed in a consent decree to review its regulation of oil and natural gas waste. However, in April 2019, the EPA concluded that revisions to the federal regulations for the management of oil and natural gas waste are not necessary at this time. Any changes in such laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Although we do not believe the current costs of managing our wastes, as presently classified, to be significant, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Remediation of Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, which we refer to as CERCLA or the “Superfund” law, and analogous state laws, generally impose liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed “responsible parties” are subject to strict liability that, in some circumstances, may be joint and several for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of our operations, we use materials that, if released, would be subject to CERCLA and comparable state statutes. Therefore, governmental agencies or third parties may seek to hold us responsible under CERCLA and comparable state statutes for all or part of the costs to clean up sites at which such “hazardous substances” have been released.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the “Clean Water Act,” or the CWA, the Safe Drinking Water Act, the Oil Pollution Act, or the OPA, and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit.

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers, or the Corps, jointly promulgated final rules redefining the scope of waters protected under the CWA. However, on October 22, 2019, the agencies published a final rule to repeal the 2015 rules. The 2015 rule and the 2019 repeal are subject to several ongoing legal challenges. Also, on April 21, 2020, the EPA and the Corps published a final rule replacing the 2015 rule, and significantly reducing the waters subject to federal regulation under the CWA. As a result of such recent developments, substantial uncertainty exists regarding the scope of waters protected under the CWA. Several state and environmental groups have challenged the replacement rule and, on January 20, 2021, the Biden Administration directed the EPA and the Corps to review the rule. To the extent the rules expand the range of properties subject to the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants, which regulations are discussed in more detail below under the caption “–Regulation of Hydraulic Fracturing.” Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The OPA is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict liability that, in some circumstances, may be joint and several for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Non-compliance with the CWA or the OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in material compliance with the requirements of each of these laws.

Air Emissions. The federal Clean Air Act, or the CAA, as amended, and comparable state laws and regulations, regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. For example, on August 16, 2012, the EPA published final regulations under the federal CAA that establish new emission controls for oil and natural gas production and processing operations, which are discussed in more detail below in "—Regulation of Hydraulic Fracturing." Also, on May 12, 2016, the EPA issued a final rule regarding the criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. These laws and regulations may increase the costs of compliance for some facilities we own or operate, and federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations. We believe that we are in substantial compliance with all applicable air emissions regulations and that we hold all necessary and valid construction and operating permits for our operations. Obtaining or renewing permits has the potential to delay the development of oil and natural gas projects.

Climate Change. In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases. The EPA has finalized a series of greenhouse gas monitoring, reporting and emissions control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of greenhouse gases primarily through the development of greenhouse gas emission inventories and/or regional greenhouse gas cap-and-trade programs. In addition, states have imposed increasingly stringent requirements related to the venting or flaring of gas during oil and natural gas operations. For example, on November 4, 2020, the Texas Railroad Commission adopted new guidance on when flaring is permissible, requiring operators to submit more specific information to justify the need to flare or vent gas.

At the international level, in December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of greenhouse gases. The Agreement went into effect on November 4, 2016. The Agreement establishes a framework for the parties to cooperate and report actions to reduce greenhouse gas emissions. Although the United States withdrew from the Paris Agreement effective November 4, 2020, President Biden issued an Executive Order on January 20, 2021 to rejoin the Paris Agreement, which went into effect on February 19, 2021. The United States has indicated its plan to announce in advance of an April 22, 2021 climate summit its nationally determined contribution, or its commitment to reduce its national greenhouse gas emissions to meet this objective. Furthermore, many state and local leaders have stated their intent to intensify efforts to support the commitments set forth in the international accord.

Restrictions on emissions of methane or carbon dioxide that may be imposed could adversely impact the demand for, price of, and value of our products and reserves. As our operations also emit greenhouse gases directly, current and future laws or regulations limiting such emissions could increase our own costs. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Furthermore, claims have been made against certain energy companies alleging that greenhouse gas emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals or public entities may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other liabilities. While our business is not a party to any such litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could significantly impact our operations and could have an adverse impact on our financial condition.

Moreover, climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornadoes and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially hotter or colder than their historical averages. Extreme weather conditions, such as, for example, the recent severe winter storms in the Permian Basin, can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time, we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

Regulation of Hydraulic Fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act.

On June 28, 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and natural gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

On August 16, 2012, the EPA published final regulations under the federal CAA that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rules seek to achieve a 95% reduction in volatile organic compounds emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. In particular, on May 12, 2016, the EPA amended its regulations to impose new standards for methane and volatile organic compounds emissions for certain new, modified, and reconstructed equipment, processes, and activities across the oil and natural gas sector. However, in a March 28, 2017 executive order, the Trump Administration directed the EPA to review the 2016 regulations and, if appropriate, to initiate a rulemaking to rescind or revise them consistent with the stated policy of promoting clean and safe development of the nation's energy resources, while at the same time avoiding regulatory burdens that unnecessarily encumber energy production. Accordingly, on August 13, 2020, the EPA issued final amendments to the 2012 and 2016 New Source Performance standards to ease regulatory burdens, including rescinding standards applicable to transmission or storage segments and eliminating methane requirements altogether. Various state, municipal and environmental groups have challenged the amendments and, on January 20, 2021, President Biden issued an executive order directing the EPA to review the amendments consistent with several policy objective, including reducing greenhouse gas emissions. Thus substantial uncertainty exists regarding the scope of the New Source Performance standards for oil and natural gas operations. The 2012 and 2016 New Source Performance standards, to the extent implemented, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

Furthermore, there are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. On December 13, 2016, the EPA released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Several states, including Texas, and local jurisdictions, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. The Texas Legislature adopted legislation, effective September 1, 2011, requiring oil and natural gas operators to publicly disclose the chemicals used in the hydraulic fracturing process. The Texas Railroad Commission adopted rules and regulations implementing this legislation that apply to all wells for which the Texas Railroad Commission issues an initial drilling permit after February 1, 2012. The law requires that the well operator disclose the list of chemical ingredients subject to the requirements of OSHA for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Also, in May 2013, the Texas Railroad Commission adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The rules took effect in January 2014. Additionally, on October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments, which became effective on November 17, 2014, also clarify the Texas Railroad Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Texas Railroad Commission has used this authority to deny permits for waste disposal wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to permitting delays and potential increases in costs. Such changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

Endangered Species

The federal Endangered Species Act, or ESA, and analogous state laws restrict activities that may affect listed endangered or threatened species or their habitats. If endangered species are located in areas where we operate, our operations or any work performed related to them could be prohibited or delayed or expensive mitigation may be required. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in compliance with the ESA. On August 12, 2019, the U.S. Fish and Wildlife Service and the National Oceanic and Atmospheric Administration's National Marine Fisheries Service jointly published final rules that, among other things, tighten the critical habitat designation process and eliminate certain automatic protections for threatened species going forward. Nevertheless, the designation of previously unprotected species in areas where we operate as threatened or endangered could result in the imposition of restrictions on our operations and consequently have a material adverse effect on our business.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations that are binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. FERC's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of condensate and oil and natural gas liquids are not currently regulated and are made at market prices.

Drilling and Production. Our operations are subject to various types of regulation at the federal, state and local level. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. The state, and some counties and municipalities, in which we operate also regulate one or more of the following; the location of wells; the method of drilling and casing wells; the timing of construction or drilling activities, including seasonal wildlife closures; the rates of production or "allowables"; the surface use and restoration of properties upon which wells are drilled; the plugging and abandoning of wells; and notice to, and consultation with, surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but we cannot assure you that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements for the plugging and abandonment of wells, closure or decommissioning of production facilities and pipelines and for site restoration in areas where we operate. Although the Corps does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation. Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Since 1978, various federal laws have been enacted which have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in "first sales," which include all of our sales of our own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under FERC's current regulatory regime, transmission services are provided on an open-access, non-discriminatory basis at cost-based rates or negotiated rates. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting gas to point-of-sale locations.

Natural Gas Gathering. Although FERC has not made a formal determination with respect to the facilities Rattler LLC considers to be natural gas gathering pipelines, Rattler believes that its natural gas gathering pipelines meet the traditional tests that FERC has used to determine that pipelines perform primarily a gathering function and are, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated interstate transportation services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of gathering facilities is subject to change based on future determinations by FERC, the courts or Congress. If FERC were to consider the status of an individual facility and determine that the facility or services provided by it are not exempt from FERC regulation under the Natural Gas Act of 1938, or NGA, and that the facility provides interstate transportation service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by FERC under the NGA or the Natural Gas Policy Act, or NGPA. Such regulation could decrease revenue, increase operating costs and, depending upon the facility in question, adversely affect results of operations and cash flow. In addition, if any of the facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by FERC.

Even though Rattler LLC considers its natural gas gathering pipelines to be exempt from the jurisdiction of FERC under the NGA, FERC regulation of interstate natural gas transportation pipelines may indirectly impact gathering services. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release and market center promotion may indirectly affect intrastate markets and gathering services. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, there can be no assurance that the FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the natural gas gathering services.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Rattler LLC's natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. We cannot predict what effect, if any, such changes might have on Rattler's or our operations, but additional capital expenditures and increased operating costs may result depending on future legislative and regulatory changes.

Oil Sales and Transportation. Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act, and our subsidiary Rattler LLC has a tariff on file with FERC to perform gathering service in interstate commerce. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any materially different way than such regulation will affect the operations of our competitors.

Further, interstate and intrastate common carrier oil pipelines, including our subsidiary Rattler LLC, must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Safety and Maintenance Regulation. In our midstream operations, Rattler LLC is subject to regulation by the U.S. Department of Transportation, or DOT, under the Hazardous Liquids Pipeline Safety Act of 1979, or HLPSA, and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of pipeline facilities. HLPSA covers petroleum and petroleum products, including natural gas liquids and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the United States Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

Rattler LLC is also subject to the Natural Gas Pipeline Safety Act of 1968, or NGPSA, and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all United States crude oil and natural gas transportation pipelines and some gathering pipelines in high-consequence areas within ten years. DOT, through the Pipeline and Hazardous Materials Safety Administration, or PHMSA, has developed regulations implementing the Pipeline Safety Improvement Act that requires pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

The Pipeline Safety and Job Creation Act, enacted in 2011, and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016, also known as the PIPES Act, enacted in 2016, amended the HLPSA and NGPSA and increased safety regulation. The Pipeline Safety and Job Creation Act doubles the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1.0 million to $2.0 million for a related series of violations (now increased for inflation to $218,647 and $2,186,465, respectively), and provides that these maximum penalty caps do not apply to civil enforcement actions, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines, including the expansion of integrity management, use of automatic and remote-controlled shut-off valves, leak detection systems, sufficiency of existing regulation of gathering pipelines, use of excess flow valves, verification of maximum allowable operating pressure, incident notification, and other pipeline-safety related requirements. The PIPES Act ensures that the PHMSA completes the Pipeline Safety and Job Creation Act requirements; reforms PHMSA to be a more dynamic, data-driven regulator; and closes gaps in federal standards.

PHMSA has undertaken rulemakings to address many areas of this legislation. For example, on October 1, 2019, PHMSA published final rules to expand its integrity management requirements and impose new pressure testing requirements on regulated pipelines, including certain segments outside High Consequence Areas. The rules, once effective, also extend reporting requirements to certain previously unregulated gathering lines. The safety enhancement requirements and other provisions of the Pipeline Safety and Job Creation Act and the PIPES Act, as well as any implementation of PHMSA rules thereunder and/or related rule making proceedings, could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position. In addition, any material penalties or fines issued to us under these or other statutes, rules, regulations or orders could have an adverse impact on our business, financial condition, results of operation and cash flow.

States are largely preempted by federal law from regulating pipeline safety but may assume responsibility for enforcing intrastate pipeline regulations at least as stringent as the federal standards, and many states have undertaken responsibility to enforce the federal standards. The Railroad Commission of Texas is the agency vested with intrastate natural gas pipeline regulatory and enforcement authority in Texas. The Commission's regulations adopt by reference the minimum federal safety standards for the transportation of natural gas. In addition, on December 17, 2019, the Commission adopted rules requiring that operators of gathering lines take 'appropriate' actions to fix safety hazards. We do not anticipate any significant problems in complying with applicable federal and state laws and regulations in Texas. Our gathering pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

In addition, we are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes, whose purpose is to protect the health and safety of workers. Moreover, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. Rattler LLC and the entities in which it owns an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above specified thresholds, or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt from these standards. Also, the Department of Homeland Security and other agencies such as the EPA continue to develop regulations concerning the security of industrial facilities, including crude oil and natural gas facilities. We are subject to a number of requirements and must prepare Federal Response Plans to comply. We must also prepare Risk Management Plans under the regulations promulgated by the EPA to implement the requirements under the CAA to prevent the accidental release of extremely hazardous substances. We have an internal program of inspection designed to monitor and enforce compliance with safeguard and security requirements. We believe that we are in compliance in all material respects with all applicable laws and regulations relating to safety and security.

State Regulation. Texas regulates the drilling for, and the production, gathering and sale of, oil and natural gas, including imposing severance taxes and requirements for obtaining drilling permits. Texas currently imposes a 4.6% severance tax on oil production and a 7.5% severance tax on natural gas production. States also regulate the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and natural gas resources. States may regulate rates of production and may establish maximum daily production allowables from oil and natural gas wells based on market demand or resource conservation, or both. States do not regulate wellhead prices or engage in other similar direct economic regulation, but we cannot assure you that they will not do so in the future. The effect of these regulations may be to limit the amount of oil and natural gas that may be produced from our wells and to limit the number of wells or locations we can drill.

The petroleum industry is also subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to resource conservation and equal employment opportunity. We do not believe that compliance with these laws will have a material adverse effect on us.

Operational Hazards and Insurance

The oil and natural gas industry involves a variety of operating risks, including the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies for onshore property (oil lease property/production equipment) for selected locations, rig physical damage protection, control of well protection for selected wells, comprehensive general liability, commercial automobile, workers compensation, pollution liability (claims made coverage with a policy retroactive date), excess umbrella liability and other coverage.

Our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these operational hazards could cause a significant disruption to our business. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. See Item 1A. “Risk Factors–Risks Related to the Oil and Natural Gas Industry and Our Business–Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.”

We reevaluate the purchase of insurance, policy terms and limits annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

Generally, we also require our third-party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider.

Human Capital

We have developed a culture grounded upon the solid foundation of our core values—leadership, integrity, excellence, people and teamwork—that are adhered to throughout our company. We set a high bar for all of our employees in terms of how they operate and interact, both within the office and out in the field. We challenge them to identify new ways to foster a better future for themselves and for us.

As of December 31, 2020, we had approximately 732 full time employees. None of our employees are represented by labor unions or covered by any collective bargaining agreements. We also utilize independent contractors and consultants involved in land, technical, regulatory and other disciplines to assist our full-time employees.

Diversity and Inclusion

Equal employment opportunity is one of our core tenets and, as such, our employment decisions are based on merit, qualifications, competencies and contributions. We actively seek to attract and retain an increasingly diverse workforce and continue to cultivate an inclusive and respectful work environment. We deeply value the perspectives and experiences from our diverse team and are proud of our team, rich in a range of ethnic, cultural and ideological backgrounds. Nearly a third of our employees are women and 25% self-identify as ethnic minorities. We have taken various actions during 2020 to increase the diversity in our candidate pool, and broaden our outreach, particularly within our intern program, through various student organizations to support this inclusion effort.

Health and Safety

Protecting employees, the public and the environment is a top priority in our operations and in the way we manage our assets. We are focused on minimizing the risk of workplace incidents and preparing for emergencies as an indelible element of our corporate responsibility. We also strive to comply with all applicable health, safety and environmental standards, laws and regulations.

Through a unified orientation initiative called Basin United, we and other oil and natural gas operators have committed to reduce injuries and fatalities in our industry. We are aligning our employees and independent contractors around the International Association of Oil & Gas Producers Life Saving Rules, safety culture improvements, safety leadership actions and human performance principles. We also involve employees from all operational levels on our Safety Committee, which provides suggested improvements to the overall safety program, recommended preventative measures based on reviewing vehicle and personnel incidents, safety and environmental audits at operational locations and audit and oversight of the Diamondback Hazard Communication Program, in accordance with OSHA regulations.

From 2016 through 2020, we had zero employee work-related fatalities. Our employee OSHA recordable cases, comprising work-related injuries and illnesses that require medical treatment beyond first aid, totaled three in 2020, flat from three in 2019. Our employee total recordable incident rate (TRIR) in 2020 was flat from 2019 and lost-time incident rate (LTIR) decreased in 2020. We have set a short-term target of maintaining an employee TRIR of 0.5 or less.

Training and Development

We support employees in pursuing training opportunities to expand their professional skills. Our internal course offerings in 2020 included a wide array of topics such as Excel Power Lunch, Performance Management, COVID-19 Safety Training, as well as various and extensive safety and other compliance training sessions. In 2020, our team completed nearly 8,000 hours of training. Additionally, our people also undergo training and education each year on regulatory compliance, industry standards and innovative opportunities to effectively manage the challenges of developing our resources.

Our Facilities

Our corporate headquarters is located at the Fasken Center in Midland, Texas. We also lease additional office space in Houston, Texas, Midland, Texas and Oklahoma City, Oklahoma.

Availability of Company Reports

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports are available free of charge on the Investor Relations page of our website at www.diamondbackenergy.com as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Information contained on, or connected to, our website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Risk Factors Summary

The following is a summary of the principal risks that could adversely affect our business, operations and financial results. Please refer to Item 1A "Risk Factors" of this Form 10-K below for additional discussion of the risks summarized in this Risk Factors Summary.

Risks Relating to the Pending Merger and to Diamondback Following the Completion of the Pending Merger

- The pending merger may not be completed and the merger agreement may be terminated in accordance with its terms, which could negatively impact the price of our common stock and our results.
- We will incur significant transaction and merger-related costs in connection with the pending merger.
- We and our subsidiaries will have substantial indebtedness after giving effect to the pending merger, which may limit our financial flexibility and adversely affect our financial results.
- An adverse ruling in the pending or any future lawsuits relating to the merger could result in an injunction preventing the completion of the merger and/or substantial costs to us and QEP.
- We may not achieve the intended benefits of the pending merger or do so within the intended timeframe, and it may not be accretive, and may be dilutive, to our earnings per share.
- The market price of our common stock will continue to fluctuate after the pending merger is completed, and may decline if the benefits of the pending merger do not meet the expectations of financial analysts.
- Following the completion of the pending merger, we may incorporate QEP's hedging activities into our business and, as a result, may be exposed to additional commodity price risks arising from such hedges.
- The combined company may record goodwill and other intangible assets that could become impaired and result in material non-cash charges to the results of operations of the combined company in the future.
- The combined company may not be able to retain customers or suppliers, and customers or suppliers may seek to modify contractual obligations with the combined company, either of which could have an adverse effect on the combined company's business and operations.

Risks Related to the Oil and Natural Gas Industry and Our Business

- Our business and operations have been and will likely continue to be adversely affected by the ongoing COVID-19 pandemic.
- Market conditions and particularly volatility in prices for oil and natural gas may continue to adversely affect our revenue, cash flows, profitability, growth, production and the present value of our estimated reserves.
- We may be unable to obtain needed capital or financing on satisfactory terms or at all to fund our acquisitions or development activities, which could lead to a loss of properties and a decline in our oil and natural gas reserves and future production.
- Our failure to successfully identify, complete and integrate pending and future acquisitions of properties or businesses could reduce our earnings, and title defects in the properties in which we invest may lead to losses.
- Our identified potential drilling locations are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.
- Despite our hedging activities, we may be adversely affected by continuing and prolonged declines in the price of oil and may be exposed to other risks, including counterparty credit risk.
- If production from our Permian Basin acreage decreases, we may fail to meet our obligations to deliver specified quantities of oil under our oil purchase contract, which may adversely affect our operations.
- The inability of one or more of our customers to meet their obligations, or loss of one or more of our significant purchasers, may adversely affect our financial results.
- Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.

- Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- We are vulnerable to risks associated with our primary operations concentrated in a single geographic area.
- If transportation or other facilities, certain of which we do not control, or rigs, equipment, raw materials, oil services or personnel are unavailable, our operations could be interrupted and our revenues reduced.
- Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive and may impose restrictions on our operations.
- Recent and future U.S. tax legislation may adversely affect our business, results of operations, financial condition and cash flow.
- Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations.
- A terrorist attack or armed conflict could harm our business and could adversely affect our business.
- A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

Risks Related to Our Indebtedness

- Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under our indebtedness, and we and our subsidiaries may be able to incur substantial additional indebtedness in the future.
- A reduction in availability under our revolving credit facility and the inability to otherwise obtain financing for our capital programs could require us to curtail our capital expenditures.
- Restrictive covenants in certain of our existing and future debt instruments may limit our ability to respond to changes in market conditions or pursue business opportunities.
- We depend on our subsidiaries for dividends, distributions and other payments.
- If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.
- Borrowings under our, Viper LLC's and Rattler LLC's revolving credit facilities expose us to interest rate risk.

Risks Related to Our Common Stock

- The corporate opportunity provisions in our certificate of incorporation could enable affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.
- If the price of our common stock fluctuates significantly, your investment could lose value.
- The declaration of dividends and any repurchases of our common stock are each within the discretion of our board of directors, and there is no guarantee that we will pay any dividends on or repurchases of our common stock in the future or at levels anticipated by our stockholders.
- A change of control could limit our use of net operating losses.
- If our operating results do not meet expectations of securities or industry analysts, our stock price could decline.
- We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.
- Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

ITEM 1A. RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. The following is a summary of some of the material risks relating to our business activities. Other risks are described in Item 1. "Business and Properties," Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk." These risks are not the only risks we face. We could also face additional risks and uncertainties not currently known to us or that we currently deem to be immaterial. If any of these risks actually occurs, it could materially harm our business, financial condition or results of operations and the trading price of our shares could decline.

Risks Relating to the Pending Merger

The pending merger may not be completed and the merger agreement may be terminated in accordance with its terms. Failure to complete the pending merger could negatively impact the price of shares of our common stock and our future businesses and financial results.

The pending merger is subject to a number of conditions that must be satisfied, including the approval by QEP stockholders of the merger agreement proposal, or, to the extent permitted by applicable law, waived, in each case prior to the completion of the pending merger. The conditions to the completion of the pending merger, some of which are beyond our control, may not be satisfied or waived in a timely manner or at all, and, accordingly, the pending merger may be delayed or may not be completed.

In addition, if the pending merger is not completed by June 30, 2021, or, in certain instances, on or before September 30, 2021, either we or QEP may choose not to proceed with the pending merger by terminating the merger agreement, and the parties can mutually decide to terminate the merger agreement at any time, before or after stockholder approval. Further, either we or QEP may elect to terminate the merger agreement in certain other circumstances specified in the merger agreement. If the transactions contemplated by the merger agreement are not completed for any reason, our ongoing business, financial condition and financial results may be adversely affected. Without realizing any of the benefits of having completed the transactions, we will be subject to a number of risks, including the following:

- we may be required to pay our costs relating to the transactions, which are substantial, such as legal, accounting, financial advisory and printing fees, whether or not the transactions are completed;
- time and resources committed by our management to matters relating to the transactions could otherwise have been devoted to pursuing other beneficial opportunities;
- we may experience negative reactions from financial markets, including negative impacts on the price of our common stock, including to the extent that the current market price reflects a market assumption that the transactions will be completed;
- we may experience negative reactions from employees, customers or vendors; and
- since the merger agreement restricts the conduct of our business prior to completion of the pending merger, we may not have been able to take certain actions during the pendency of the merger that would have benefitted us as an independent company and the opportunity to take such actions may no longer be available.

We will be subject to business uncertainties while the merger is pending, which could adversely affect our business.

Uncertainty about the effect of the pending merger on employees, industry contacts and business partners may have an adverse effect on us. These uncertainties may impair our ability to attract, retain and motivate key personnel until the pending merger is completed and for a period of time thereafter and could cause industry contacts, business partners and others that deal with us to seek to change their existing business relationships with us. In addition, the merger agreement restricts the parties to the merger agreement from entering into certain corporate transactions and taking other specified actions without the consent of the other party. These restrictions may prevent us from pursuing attractive business opportunities that may arise prior to the completion of the pending merger.

We will incur significant transaction and merger-related costs in connection with the pending merger, which may be in excess of those anticipated by us.

We have incurred and expect to continue to incur a number of non-recurring costs associated with negotiating and completing the pending merger, combining the operations of the two companies and achieving desired synergies. These fees and costs have been, and will continue to be, substantial. The substantial majority of non-recurring expenses will consist of transaction costs related to the pending merger and include, among others, employee retention costs, fees paid to financial, legal and accounting advisors, severance and benefit costs and filing fees.

We will also incur transaction fees and costs related to the integration of the companies, which may be substantial. Moreover, we may incur additional unanticipated expenses in connection with the pending merger and the integration, including costs associated with any stockholder litigation related to the pending merger. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow us to offset integration-related costs over time, this net benefit may not be achieved in the near term, or at all. The costs described above, as well as other unanticipated costs and expenses, could have a material adverse effect on the financial condition and operating results of the combined company following the completion of the pending merger.

We and our subsidiaries will have substantial indebtedness after giving effect to the pending merger, which may limit our financial flexibility and adversely affect our financial results.

Under the merger agreement, QEP's outstanding debt (other than its existing credit facility) will remain outstanding, which debt, as of December 31, 2020 was approximately $1.6 billion and consisted of amounts outstanding under QEP's senior notes. As of December 31, 2020, we had total long-term debt of approximately $5.6 billion, consisting primarily of the amounts outstanding under our revolving credit facility, our senior unsecured notes, the notes issued by our subsidiary Energen Corporation, the senior notes issued by our publicly traded subsidiaries, Viper and Rattler, and the amounts outstanding under Viper's and Rattler's revolving credit facilities.

Our pro forma indebtedness as of December 31, 2020, assuming consummation of the pending merger had occurred on such date and QEP's senior notes remain outstanding, would have been approximately $7.4 billion, representing an increase in comparison to our indebtedness on a recent historical basis. We believe that post-merger we will retain our investment grade credit ratings and retire the combined company's pro forma debt at a faster rate than either company would have been able to do absent the pending merger. However, any increase in our indebtedness could have adverse effects on our financial condition and results of operations, including:

- increasing difficulty to satisfy our obligations with respect to our debt obligations, including any repurchase obligations that may arise thereunder;
- diverting a significant portion of our cash flows to service our indebtedness, which could reduce the funds available to us for operations and other purposes;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that we would be unable to pursue due to our indebtedness;
- limiting our ability to access the capital markets to raise capital on favorable terms;
- impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- increasing our vulnerability to interest rate increases, as our borrowings under our revolving credit facility are at variable interest rates.

We believe that the combined company will have flexibility to repay, refinance, repurchase, redeem, exchange or otherwise terminate large portions of our outstanding debt obligations. However, there can be no guarantee that we would be able to execute such refinancings on favorable terms or at all, and a high level of indebtedness increases the risk that we may default on our debt obligations, including from the debt obligations of QEP. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. Our future performance depends on many factors independent of the pending merger, some of which are beyond our control, such as general economic conditions and oil and natural gas prices. We may not be able to generate sufficient cash flows to pay the interest on our debt, and future working capital, borrowings or equity financing may not be available to pay or refinance such debt.

Lawsuits have been filed against QEP, us, Merger Sub and the members of the QEP board in connection with the merger and additional lawsuits may be filed in the future. An adverse ruling in any such lawsuit could result in an injunction preventing the completion of the merger and/or substantial costs to us and QEP.

Securities class action lawsuits and derivative lawsuits are often brought against public companies that have entered into acquisition, merger or other business combination agreements like the merger agreement. Even if such a lawsuit is without merit, defending against these claims can result in substantial costs and divert management time and resources.

As of February 22, 2021, nine individual lawsuits have been filed by purported QEP stockholders in United States District Courts in connection with the proposed merger. All nine lawsuits name QEP and the members of the QEP board as defendants, and two of the nine lawsuits name us and Merger Sub as defendants. The complaints allege, among other things, that the registration statements relating to the merger on Form S-4 filed by us on January 22, 2021, as amended on Form S-4/A filed on February 3, 2021, and the Schedule 14A Definitive Proxy Statement filed by QEP on February 10, 2021 fail to provide certain allegedly material information concerning the proposed merger in violation of Sections 14(a) and 20(a) of the Exchange Act and Rule 14a-9 promulgated thereunder. In addition to these allegations, some of the complaints allege that the merger consideration to be received by the QEP stockholders in the merger is unfair because the value of the QEP common stock is in excess of the value of the merger consideration, that the "no solicitation" clause in the merger agreement is improper and that the termination fee contemplated by the merger agreement is excessive. Some of the complaints also assert a breach of fiduciary duty claim under state law against individual QEP board members. Among other remedies, the plaintiffs seek to enjoin the completion of the proposed merger, a recission of the completed merger or rescissory damages, an accounting of damages suffered by the plaintiff, an award of plaintiff's expenses and attorney's fees, and other relief.

Each of us and QEP believes that the allegations in the complaints are without merit. Additional lawsuits arising out of the merger may also be filed in the future.

One of the conditions to the closing of the merger is that no injunction by any governmental entity having jurisdiction over us, QEP or Merger Sub has been entered and continues to be in effect and no law has been adopted, in either case that prohibits the closing of the merger. Consequently, if a plaintiff is successful in obtaining an injunction prohibiting completion of the merger, that injunction may delay or prevent the merger from being completed within the expected timeframe or at all, which may adversely affect our business, financial position and results of operations.

Additionally, there can be no assurance that any of the defendants will be successful in the outcome of the lawsuits filed thus far or any potential future lawsuits. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect our business, financial condition, results of operations and cash flows.

Risk Factors Relating to Diamondback Following the Completion of the Pending Merger

The integration of QEP into our business may not be as successful as anticipated, and we may not achieve the intended benefits or do so within the intended timeframe.

The pending merger involves numerous operational, strategic, financial, accounting, legal, tax and other risks, potential liabilities associated with the acquired businesses, and uncertainties related to design, operation and integration of QEP's internal control over financial reporting. Difficulties in integrating QEP into our business may result in us performing differently than expected, operational challenges, or the failure to realize anticipated expense-related efficiencies. Potential difficulties that may be encountered in the integration process include, among others:

- the inability to successfully integrate QEP into our business in a manner that permits us to achieve the full revenue and cost savings anticipated from the pending merger;
- complexities associated with managing the larger, more complex, integrated business;
- not realizing anticipated operating synergies;
- integrating personnel from the two companies and the loss of key employees;
- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with the pending merger;
- integrating relationships with industry contacts and business partners;
- performance shortfalls as a result of the diversion of management's attention caused by completing the pending merger and integrating QEP's operations into our operations; and
- the disruption of, or the loss of momentum in, ongoing business or inconsistencies in standards, controls, procedures and policies.

Additionally, the success of the pending merger will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining our and QEP's businesses, including operational and other synergies that we believe the combined company will achieve. The anticipated benefits and cost savings of the pending merger may not be realized fully or at all, may take longer to realize than expected, or could have other adverse effects that we do not currently foresee.

Our results may suffer if we do not effectively manage our expanded operations following the pending merger.

The success of the pending merger will depend, in part, on our ability to realize the anticipated benefits and cost savings from combining our and QEP's businesses, including the need to integrate the operations and business of QEP into our existing business in an efficient and timely manner, to combine systems and management controls and to integrate relationships with customers, vendors, industry contacts and business partners.

The anticipated benefits and cost savings of the pending merger may not be realized fully or at all, may take longer to realize than expected or could have other adverse effects that we do not currently foresee. Some of the assumptions that we have made, such as the achievement of operating synergies, may not be realized. There could also be unknown liabilities and unforeseen expenses associated with the pending merger that were not discovered in the due diligence review conducted by each company prior to entering into the merger agreement.

The pending merger may not be accretive, and may be dilutive, to our earnings per share, which may negatively affect the market price of our common stock.

Because shares of our common stock will be issued in the pending merger, it is possible that, although we currently expect the merger to be accretive to earnings per share, the merger may be dilutive to our earnings per share, which could negatively affect the market price of our common stock.

In connection with the completion of the pending merger, based on the number of issued and outstanding shares of QEP common stock as of February 22, 2021 and the number of outstanding QEP equity awards currently estimated to be payable in our common stock following the merger, we will issue up to approximately 12.4 million shares of our common stock. The issuance of these new shares of our common stock could have the effect of depressing the market price of our common stock, through dilution of earnings per share or otherwise. Any dilution of, or delay of any accretion to, our earnings per share could cause the price of shares of our common stock to decline or increase at a reduced rate.

Furthermore, our current stockholders may not wish to continue to invest in the additional operations of the combined company, or for other reasons may wish to dispose of some or all of their interests in the combined company, and as a result may seek to sell their shares of our common stock following, or in anticipation of, completion of the pending merger. The merger agreement does not restrict the ability of former QEP stockholders to sell such shares of our common stock following completion of the pending merger. Therefore, these sales (or the perception that these sales may occur), coupled with the increase in the outstanding number of shares of our common stock, may affect the market for, and the market price of, our common stock in an adverse manner.

If the pending merger is completed and our stockholders, including former QEP stockholders, sell substantial amounts of our common stock in the public market following the consummation of the pending merger, the market price of our common stock may decrease. These sales might also make it more difficult for us to raise capital by selling equity or equity-related securities at a time and price that it otherwise would deem appropriate.

The market price of our common stock will continue to fluctuate after the pending merger, and may decline if the benefits of the pending merger do not meet the expectations of financial analysts.

Upon completion of the pending merger, holders of QEP common stock who receive merger consideration will become holders of shares of our common stock. The market price of our common stock may fluctuate significantly following completion of the pending merger and holders of QEP common stock could lose some or all of the value of their investment in our common stock. In addition, the stock market has recently experienced significant price and volume fluctuations which could, if such fluctuations continue to occur, have a material adverse effect on the market for, or liquidity of, our common stock, regardless of our actual operating performance.

The market price of our common stock may be affected by factors different from those that historically have affected QEP common stock or our common stock.

Our business differs from that of QEP in certain respects, and, accordingly, our financial position or results of operations and/or cash flows after the pending merger is completed, as well as the market price of our common stock, may be affected by factors different from those currently affecting our financial position or results of operations and/or cash flows as an independent standalone company.

Following the completion of the pending merger, we may incorporate QEP's hedging activities into our business and, as a result, may be exposed to additional commodity price risks arising from such hedges.

To mitigate its exposure to changes in commodity prices, QEP hedges oil and natural gas prices from time to time, primarily through the use of certain derivative instruments. If we assume QEP's existing derivative instruments or if QEP enters into additional derivative instruments prior to the completion of the pending merger, we will bear the economic impact of the contracts following the completion of the pending merger. Actual crude oil and natural gas prices may differ from the combined company's expectations and, as a result, such derivative instruments may have a negative impact on our business.

The combined company may record goodwill and other intangible assets that could become impaired and result in material non-cash charges to the results of operations of the combined company in the future.

The pending merger will be accounted for as an acquisition by us in accordance with GAAP. Under the acquisition method of accounting, the assets and liabilities of QEP and its subsidiaries will be recorded, as of completion of the pending merger, at their respective fair values and added to those of us. Our reported financial condition and results of operations for the periods after completion of the pending merger will reflect QEP balances and results after completion of the pending merger but will not be restated retroactively to reflect the historical financial position or results of operations of QEP and its subsidiaries for periods prior to the completion of the pending merger.

Under the acquisition method of accounting, the total purchase price will be allocated to QEP's tangible assets and liabilities and identifiable intangible assets based on their fair values as of the date of completion of the pending merger. The excess of the purchase price over those fair values will be recorded as goodwill. We expect that the pending merger may result in the creation of goodwill based upon the application of the acquisition method of accounting. To the extent goodwill or intangibles are recorded and the values become impaired, the combined company may be required to recognize material non-cash charges relating to such impairment. The combined company's operating results may be significantly impacted from both the impairment and underlying trends in the business that triggered the impairment.

The combined company may not be able to retain customers or suppliers, and customers or suppliers may seek to modify contractual obligations with the combined company, either of which could have an adverse effect on the combined company's business and operations. Third parties may terminate or alter existing contracts or relationships with us as a result of the pending merger.

As a result of the pending merger, the combined company may experience impacts on relationships with customers and suppliers that may harm the combined company's business and results of operations. Certain customers or suppliers may seek to terminate or modify contractual obligations following the completion of the pending merger whether or not contractual rights are triggered as a result of the pending merger. There can be no guarantee that customers and suppliers will remain with or continue to have a relationship with the combined company or do so on the same or similar contractual terms following the closing of the pending merger. If any customers or suppliers seek to terminate or modify contractual obligations or discontinue their relationships with the combined company, then the combined company's business and results of operations may be harmed. If the combined company's suppliers were to seek to terminate or modify an arrangement with the combined company, then the combined company may be unable to procure necessary supplies or services from other suppliers in a timely and efficient manner and on acceptable terms, or at all.

QEP also has contracts with vendors, landlords, licensors and other business partners which may require QEP to obtain consent from these other parties in connection with the pending merger. If these consents cannot be obtained, the combined company may suffer a loss of potential future revenue, incur costs and/or lose rights that may be material to the business of the combined company. In addition, third parties with whom Diamondback or QEP currently have relationships may terminate or otherwise reduce the scope of their relationship with either party in anticipation of the closing of the pending merger. Any such disruptions could limit the combined company's ability to achieve the anticipated benefits of the pending merger. The adverse effect of any such disruptions could also be exacerbated by a delay in the completion of the pending merger or by a termination of the merger agreement.

Declaration, payment and amounts of dividends, if any, distributed to our stockholders will be uncertain.

Although we have paid cash dividends on our common stock in the past, our board of directors may determine not to declare dividends in the future or may reduce the amount of dividends paid in the future. Any payment of future dividends will be at the discretion of our board of directors and will depend on our results of operations, financial condition, cash requirements, future prospects and other considerations that our board of directors deems relevant.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our business and operations have been and will likely continue to be adversely affected by the ongoing COVID-19 pandemic.

The spread of COVID-19 caused, and is continuing to cause, severe disruptions in the worldwide and U.S. economies, including contributing to the reduced global and domestic demand for oil and natural gas, which has had and will likely continue to have an adverse effect on our business, financial condition and results of operations. Moreover, since the beginning of January 2020, the COVID-19 pandemic has caused significant disruption in the financial markets both globally and in the United States. The continued spread of COVID-19 could also negatively impact the availability of key personnel necessary to conduct our business. If COVID-19 continues to spread or the response to contain or mitigate the COVID-19 pandemic through the development and availability of effective treatments and vaccines, including the vaccines recently approved by the FDA for emergency use in the U.S., is unsuccessful, we could continue to experience material adverse effects on our business, financial condition and results of operations. Due to the rapid development and fluidity of this situation, we cannot make any prediction as to the ultimate material adverse impact of the COVID -19 pandemic on our business, financial condition and results of operations.

***The sharp decline in oil and natural gas prices and continued volatility in the oil and natural gas markets have negatively impacted, and are likely to continue to negatively impact, our exploration and production activities, which has adversely impacted our business, financial condition and results of operations. In addition, lower oil and natural gas prices may adversely affect the borrowing base under our revolving credit facility and estimates of our proved reserves*.**

In early March 2020, oil prices dropped sharply and then continued to decline reaching negative levels. This was a result of multiple factors affecting the supply and demand in global oil and natural gas markets, including actions taken by OPEC members and other exporting nations impacting commodity price and production levels and a significant decrease in demand due to the ongoing COVID-19 pandemic. While OPEC members and certain other nations agreed in April 2020 to cut production and subsequently extended such production cuts through December 2020, which helped to reduce a portion of the excess supply in the market and improve crude oil prices, they agreed to increase production by 500,000 barrels per day beginning in January 2021. As a result, downward pressure on commodity prices has continued and could continue for the foreseeable future. We cannot predict if or when commodity prices will stabilize and at what levels.

As a result of the reduction in crude oil demand caused by factors discussed above, we lowered our 2020 capital budget and production guidance, curtailed near term production and reduced our rig count, all of which may be subject to further reductions or curtailments if the commodity markets and macroeconomic conditions worsen. Although we have restored our curtailed production, actions taken in response to the COVID-19 pandemic and depressed commodity pricing environment have had and are expected to continue to have an adverse effect on our business, financial results and cash flows.

Based on the results of the quarterly ceiling test, we were required to record an impairment on our proved oil and natural gas interests for the year ended December 31, 2020. If commodity prices fall below current levels, we may be required to record impairments in future periods and such impairments could be material. Further, if commodity prices decrease, our production, proved reserves and cash flows will be adversely impacted.

Other significant factors that are likely to continue to affect commodity prices in future periods include, but are not limited to, the effect of U.S. energy, monetary and trade policies, U.S. and global political and economic developments, including the Biden Administration's energy and environmental policies and the impact of the ongoing COVID-19 pandemic on conditions in the U.S. oil and natural gas industry, all of which are beyond our control.

Our results of operations may be also adversely impacted by any future government rule, regulation or order that may impose production limits, as well as pipeline capacity and storage constraints, in the Permian Basin where we operate.

We cannot predict the ultimate impact of these factors on our business, financial condition and results of operation.

Increased costs of capital could adversely affect our business.

Our business could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our activities. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our business strategy and cash flows.

Market conditions for oil and natural gas, and particularly volatility in prices for oil and natural gas, have in the past adversely affected, and may in the future adversely affect, our revenue, cash flows, profitability, growth, production and the present value of our estimated reserves.

Our revenues, operating results, profitability, future rate of growth and the carrying value of our oil and natural gas properties depend significantly upon the prevailing prices for oil and natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including; the domestic and foreign supply of oil and natural gas; the level of prices and expectations about future prices of oil and natural gas; the level of global oil and natural gas exploration and production; the cost of exploring for, developing, producing and delivering oil and natural gas; the price and quantity of foreign imports; political and economic conditions in oil producing countries, including the Middle East, Africa, South America and Russia; the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls; speculative trading in crude oil and natural gas derivative contracts; the level of consumer product demand; extreme weather conditions and other natural disasters; risks associated with operating drilling rigs; technological advances affecting energy consumption; the price and availability of alternative fuels; domestic and foreign governmental regulations and taxes; the continued threat of terrorism and the impact of military and other action, including U.S. military operations in the Middle East; global or national health concerns, including the outbreak of pandemic or contagious disease, such as COVID-19; the proximity, cost, availability and capacity of oil and natural gas pipelines and other transportation facilities; and overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil and natural gas price movements with any certainty. During 2020, NYMEX WTI prices ranged from $(37.63) to $63.27 per Bbl and the NYMEX Henry Hub price of natural gas ranged from $1.48 to $3.35 per MMBtu. If the prices of oil and natural gas decline further, our operations, financial condition and level of expenditures for the development of our oil and natural gas reserves may be materially and adversely affected.

In addition, lower oil and natural gas prices may reduce the amount of oil and natural gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs or if our production estimates change or our exploration or development activities are curtailed, full cost accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties. Reductions in our reserves could also negatively impact the borrowing base under our revolving credit facility, which could further limit our liquidity and ability to conduct additional exploration and development activities.

A significant portion of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

A significant portion of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, many of our oil and natural gas leases require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

Our development and exploration operations and our ability to complete acquisitions require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. In 2020, our total capital expenditures, including expenditures for drilling, infrastructure and additions to midstream assets, were approximately $1.9 billion. Our 2021 capital budget for drilling, completion and infrastructure, including investments in water disposal infrastructure and gathering line projects, is currently estimated to be approximately $1.4 billion to $1.6 billion, representing a decrease of 50% from our 2020 capital budget. Since completing our initial public offering in October 2012, we have financed capital expenditures primarily with borrowings under our revolving credit facility, cash generated by operations and the net proceeds from public offerings of our common stock and the senior notes.

We intend to finance our future capital expenditures for our drilling operations with cash flow from operations, while future acquisitions may also be funded from operations as well as proceeds from offerings of our debt and equity securities and borrowings under our revolving credit facility. Our cash flow from operations and access to capital are subject to a number of variables, including; our proved reserves; the volume of oil and natural gas we are able to produce from existing wells; the prices at which our oil and natural gas are sold; our ability to acquire, locate and produce economically new reserves; and our ability to borrow under our credit facility.

We cannot assure you that our operations and other capital resources will provide cash in sufficient amounts to maintain planned or future levels of capital expenditures. Further, our actual capital expenditures in 2021 could exceed our capital expenditure budget. In the event our capital expenditure requirements at any time are greater than the amount of capital we have available, we could be required to seek additional sources of capital, which may include traditional reserve base borrowings, debt financing, joint venture partnerships, production payment financings, sales of assets, offerings of debt or equity securities or other means. We cannot assure you that we will be able to obtain debt or equity financing on terms favorable to us, or at all.

If we are unable to fund our capital requirements, we may be required to curtail our operations relating to the exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves, or we may be otherwise unable to implement our development plan, complete acquisitions or take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations. In addition, a delay in or the failure to complete proposed or future infrastructure projects could delay or eliminate potential efficiencies and related cost savings.

Our success depends on finding, developing or acquiring additional reserves.

Our future success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we undertake development, exploration and other replacement activities or use third parties to accomplish these activities. We have made, and expect to make in the future, substantial capital expenditures in our business and operations for the development, production, exploration and acquisition of oil and natural gas reserves. We may not have sufficient resources to acquire additional reserves or to undertake exploration, development, production or other replacement activities, such activities may not result in significant additional reserves and we may not have success drilling productive wells at low finding and development costs. If we are unable to replace our current production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected. Furthermore, although our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Our failure to successfully identify, complete and integrate pending and future acquisitions of properties or businesses could reduce our earnings and slow our growth.

There is intense competition for acquisition opportunities in our industry. The successful acquisition of producing properties requires an assessment of several factors, including; recoverable reserves, future oil and natural gas prices and their applicable differentials, operating costs, and potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain, and we may not be able to identify attractive acquisition opportunities. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. If these acquisitions include geographic regions in which we do not currently operate, as in the case of the pending merger with QEP, we could be subject to unforeseen operating difficulties and difficulties in coordinating geographically dispersed operations, personnel and facilities. In addition, if we enter into new geographic markets, we may be subject to additional and unfamiliar legal and regulatory requirements. Compliance with regulatory requirements may impose substantial additional obligations on us and our management, cause us to expend additional time and resources in compliance activities and increase our exposure to penalties or fines for non-compliance with such additional legal requirements. Further, the success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions.

No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations. The inability to effectively manage the integration of acquisitions, including our pending acquisitions, could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and natural gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition.

Prior to the drilling of an oil or natural gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in the assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

Our project areas, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. If future wells or the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected.

Our identified potential drilling locations, which are part of our anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

At an assumed price of approximately $60.00 per Bbl WTI, we currently have approximately 10,413 gross (6,863 net) identified economic potential horizontal drilling locations in multiple horizons on our acreage. As of December 31, 2020, only 628 of our gross identified potential horizontal drilling locations were attributed to proved reserves. These drilling locations, including those without proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including the availability of capital, construction of infrastructure, inclement weather, regulatory changes and approvals, oil and natural gas prices, costs, drilling results and the availability of water. Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation. In addition, we have identified approximately 2,708 horizontal drilling locations in intervals in which we have drilled very few or no wells, which are necessarily more speculative and based on results from other operators whose acreage may not be consistent with ours. We cannot predict in advance of drilling and testing whether any particular drilling location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. Through December 31, 2020, we are the operator of, have participated in, or have acquired working interest in a total of 2,380 horizontal wells completed on our acreage, we cannot assure you that the analogies we draw from available data from these or other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Permian Basin may not be indicative of future or long-term production rates. Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in our operating results.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. In addition, in order to hold our current leases expiring in 2021, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy these rigs in this time frame, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset basis, cash flows and results of operations.

We have entered into commodity price derivatives for a portion of our production. Although we have hedged a portion of our estimated 2021 and 2022 production, we may still be adversely affected by continuing and prolonged declines in the price of oil and may be exposed to other risks, including counterparty credit risk.

We use commodity price derivatives to reduce price volatility associated with certain of our oil and natural gas sales. To the extent that the prices of oil and natural gas remain at current levels or decline further, we may not be able to economically hedge future production at the same level as our current hedges, and our results of operations and financial condition may be negatively impacted.

At settlement, market prices for commodities may exceed the contract prices in our commodity price derivatives agreements, resulting in our need to make significant cash payments to our counterparties. Further, by using commodity derivative instruments, we expose ourselves to credit risk if we are in a positive position at contract settlement and the counterparty fails to perform under the terms of the derivative contract. We do not require collateral from our counterparties.

For additional information regarding our outstanding derivative contracts as of December 31, 2020, see Note 15—Derivatives to our consolidated financial statements included elsewhere in this report.

If production from our Permian Basin acreage decreases due to decreased developmental activities, production related difficulties or otherwise, we may fail to meet our obligations to deliver specified quantities of oil under our oil purchase contract, which will result in deficiency payments to the counterparty and may have an adverse effect on our operations.

We are a party to long-term crude oil agreements under which, subject to certain terms and conditions, we are obligated to deliver specified quantities of oil to such companies. Our maximum delivery obligation under these agreements varies for different periods and depends in some cases upon certain conditions beyond our control. If production from our Permian Basin acreage decreases due to decreased developmental activities, as a result of the low commodity price environment, production related difficulties or otherwise, we may be unable to meet our obligations under our oil purchase agreements, which may result in deficiency payments to certain counterparties or a default under such agreements and may have an adverse effect on our company.

The inability of one or more of our customers to meet their obligations may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposure to credit risk is through receivables from joint interest owners on properties we operate (approximately $56 million at December 31, 2020) and receivables from purchasers of our oil and natural gas production (approximately $281 million at December 31, 2020). Joint interest receivables arise from billing 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 wish to drill. We are generally unable to control which co-owners participate in our wells.

We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. For the year ended December 31, 2020, four purchasers each accounted for more than 10% of our revenue. For each of the years ended December 31, 2019 and 2018, three purchasers each accounted for more than 10% of our revenue. This concentration of customers may impact our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. Current economic circumstances may further increase these risks. We do not require our customers to post collateral. The inability or failure of our significant customers or joint working interest owners to meet their obligations to us or their insolvency or liquidation may materially adversely affect our financial results.

Our method of accounting for investments in oil and natural gas properties may result in impairment of asset value.

We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment. All general and administrative corporate costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Income from services provided to working interest owners of properties in which we also own an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $11.30, $13.54 and $12.62 for the years ended December 31, 2020, 2019 and 2018, respectively. Depletion for oil and natural gas properties for the years ended December 31, 2020, 2019 and 2018 was $1.2 billion, $1.4 billion and $595 million, respectively.

The net capitalized costs of proved oil and natural gas properties are subject to a full cost ceiling limitation in which the costs are not allowed to exceed their related estimated future net revenues discounted at 10%. To the extent capitalized costs of evaluated oil and natural gas properties, net of accumulated depreciation, depletion, amortization and impairment, exceed the discounted future net revenues of proved oil and natural gas reserves, the excess capitalized costs are charged to expense. We use the unweighted arithmetic average first day of the month price for oil and natural gas for the 12-month period preceding the calculation date in estimating discounted future net revenues.

An impairment on proved oil and natural gas properties of $6.0 billion and $790 million was recorded for the years ended December 31, 2020 and 2019, respectively. No impairments on proved oil and natural gas properties were recorded for the year ended December 31, 2018. See Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Method of accounting for oil and natural gas properties” for a more detailed description of our method of accounting.

Our estimated reserves and EURs are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

Oil and natural gas reserve engineering is not an exact science and requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels, ultimate recoveries and operating and development costs. As a result, estimated quantities of proved reserves, projections of future production rates and the timing of development expenditures may be incorrect. The EURs for our horizontal wells are based on management’s internal estimates. Over time, we may make material changes to reserve estimates taking into account the results of actual drilling, testing and production. Also, certain assumptions regarding future oil and natural gas prices, production levels and operating and development costs may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and estimates of future net cash flows. A substantial portion of our reserve estimates are made without the benefit of a lengthy production history, which are less reliable than estimates based on a lengthy production history. Numerous changes over time to the assumptions on which our reserve estimates are based, as described above, often result in the actual quantities of oil and natural gas that we ultimately recover being different from our reserve estimates. Reserve estimates do not include any value for probable or possible reserves that may exist, nor do they include any value for unproved undeveloped acreage. The reserve estimates represent our net revenue interest in our properties.

The timing of both our production and our incurrence of costs in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves.

The standardized measure of our estimated proved reserves and our PV-10 are not necessarily the same as the current market value of our estimated proved oil reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, and our related PV-10 calculation, may not represent the current market value of our estimated proved oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties.

Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with the Financial Accounting Standard Board Codification 932, "Extractive Activities—Oil and Gas," may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 38% of our total estimated proved reserves as of December 31, 2020, were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in the reserve reports of our independent petroleum engineers assume that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or further decreases in commodity prices will reduce the future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomical. In addition, delays in the development of reserves could force us to reclassify certain of our proved reserves as unproved reserves.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties are currently geographically concentrated in the Permian Basin of West Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of crude oil, natural gas or natural gas liquids and extreme weather conditions, such as the recent severe winter storms in the Permian Basin, and their adverse impact on production volumes, availability of electrical power, road accessibility and transportation facilities. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Permian Basin, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

In addition to the geographic concentration of our producing properties described above, as of December 31, 2020, most of our proved reserves are concentrated in the Wolfberry play in the Midland Basin. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We depend upon several significant purchasers for the sale of most of our oil and natural gas production. The loss of one or more of these purchasers could, among other factors, limit our access to suitable markets for the oil and natural gas we produce.

The availability of a ready market for any oil and/or natural gas we produce depends on numerous factors beyond the control of our management, including but not limited to the extent of domestic production and imports of oil, the proximity and capacity of natural gas pipelines, the availability of skilled labor, materials and equipment, the effect of state and federal regulation of oil and natural gas production and federal regulation of natural gas sold in interstate commerce. In addition, we depend upon several significant purchasers for the sale of most of our oil and natural gas production. For the year ended December 31, 2020, four purchasers each accounted for more than 10% of our revenue. For each of the years ended December 31, 2019 and 2018, three purchasers each accounted for more than 10% of our revenue. We cannot assure you that we will continue to have ready access to suitable markets for our future oil and natural gas production. The loss of one or more of these customers, and our inability to sell our production to other customers on terms we consider acceptable, could materially and adversely affect our business, financial condition, results of operations and cash flow.

The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies, oilfield services or personnel may restrict our operations.

The oil and natural gas industry is cyclical, which can result in shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies and personnel. When shortages occur, the costs and delivery times of rigs, equipment and supplies increase and demand for, and wage rates of, qualified drilling rig crews also rise with increases in demand. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. In accordance with customary industry practice, we rely on independent third party service providers to provide most of the services necessary to drill new wells. If we are unable to secure a sufficient number of drilling rigs at reasonable costs, our financial condition and results of operations could suffer, and we may not be able to drill all of our acreage before our leases expire. In addition, we do not have long-term contracts securing the use of our existing rigs, and the operator of those rigs may choose to cease providing services to us. Shortages of drilling rigs, equipment, raw materials (particularly sand and other proppants), supplies, personnel, trucking services, tubulars, fracking and completion services and production equipment could delay or restrict our exploration and development operations, which in turn could impair our financial condition and results of operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. Over the past several years, Texas has experienced extreme drought conditions. As a result of this severe drought, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supply. If we are unable to obtain water to use in our operations from local sources, or we are unable to effectively utilize flowback water, we may be unable to economically drill for or produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

Our business operations have grown substantially since our initial public offering in October 2012 and we expect our business operations to continue to grow in the future. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

We have incurred losses from operations during certain periods since our inception and may do so in the future.

Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this report may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from our operating activities in the future.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to risks associated with drilling and completion techniques and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. In addition, to the extent we engage in horizontal drilling, those activities may adversely affect our ability to successfully drill in one or more of our identified vertical drilling locations. Furthermore, certain of the new techniques we are adopting, such as infill drilling and multi-well pad drilling, may cause irregularities or interruptions in production due to, in the case of infill drilling, offset wells being shut in and, in the case of multi-well pad drilling, the time required to drill and complete multiple wells before any such wells begin producing. The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas often have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, and/or declines in natural gas and oil prices, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and natural gas properties and the value of our undeveloped acreage could decline in the future.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities are unavailable, our operations could be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Our oil production is transported from the wellhead to our tank batteries by our gathering system, which interconnects with third party pipelines. Our natural gas production is generally transported by our gathering lines from the wellhead to an interconnection point with the purchaser. We do not control third party transportation facilities and our access to them may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. For example, on certain occasions we have experienced high line pressure at our tank batteries with occasional flaring due to the inability of the gas gathering systems in the areas in which we operate to support the increased production of natural gas in the Permian Basin. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. In addition, the amount of oil and natural gas that can be produced and sold may be subject to curtailment in certain other circumstances outside of our control, such as pipeline interruptions due to maintenance, excessive pressure, ability of downstream processing facilities to accept unprocessed gas, physical damage to the gathering or transportation system or lack of contracted capacity on such systems. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we are provided with limited, if any, notice as to when these circumstances will arise and their duration. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would adversely affect our financial condition and results of operations.

Our operations are subject to various governmental laws and regulations which require compliance that can be burdensome and expensive.

Our oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic and political conditions. Matters subject to regulation include discharge permits for drilling operations, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties and taxation. From time to time, regulatory agencies have imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below actual production capacity to conserve supplies of oil and natural gas. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, permit revocations, requirements for additional pollution controls and injunctions limiting or prohibiting some or all of our operations. Further, these laws and regulations imposed strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. In addition, federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. Even if federal regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental legislation and regulations may continue in the long-term, and at the state and local levels. See Item 1. "Business—Regulation" for a detailed description of certain laws and regulations that affect us.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect threatened or endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce our reserves.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, which we refer to as Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, which we refer to as the CFTC, the SEC, and federal regulators of financial institutions, which we refer to as the Prudential Regulators, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities.

Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC, the SEC and the Prudential Regulators have issued many rules to implement the Dodd-Frank Act, including a rule, which we refer to as the Mandatory Clearing Rule, requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, a rule, which we refer to as the End User Exception, establishing an "end user" exception to the Mandatory Clearing Rule, a rule, which we refer to as the Margin Rule, setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the Non-Financial End User Exception, and a rule imposing position limits, which we refer to as the Position Limit Rule, and also an exception to the Position Limit Rule for swaps that constitute a "bona fide hedging transaction or position" within the definition of such term under the Position Limit Rule, subject to the party claiming the exemption complying with the applicable filing, recordkeeping and reporting requirements of the Position Limit Rule, which we refer to as the Bona Fide Hedging Exception.

We qualify for the End User Exception to the Mandatory Clearing Rule, we qualify for the Non-Financial End User Exception and will not be required to post margin in connection with uncleared swaps under the Margin Rule, and each of our existing and anticipated hedging positions constitutes a "bona fide hedging transaction or position" under the Position Limit Rule and we intend to undertake the filing, recordkeeping and reporting necessary to utilize the Bona Fide Hedging Exception under the Position Limit Rule, so we do not expect to be directly affected by any of such rules. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End User Exception and will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations (including laws and regulations giving the European Union financial authorities the power to write-down amounts we may be owed on hedging agreements with counterparties subject to such laws and regulations and/or require that we accept equity interests in such counterparties in lieu of cash in satisfaction of such amounts), which we refer to collectively as Foreign Regulations, which may apply to our transactions with counterparties subject to such Foreign Regulations, which we refer to as Foreign Counterparties, and the U.S. adopted law and rules, which we call the U.S. Resolution Stay Rules, clarifying similar rights of U.S. banking authorities with respect to banking institutions subject to their regulation. The Dodd-Frank Act, the rules which have been adopted and not vacated, the Limit Rule and the U.S. Resolution Stay Rules could significantly increase the cost of our derivative contracts, materially alter the terms of our derivative contracts, reduce the availability of derivatives to us that we have historically used to protect against risks that we encounter in our business, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulation, the U.S. Resolution Stay Rules and Foreign Regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

Recently enacted U.S. tax legislation as well as future U.S. tax legislation may adversely affect our business, results of operations, financial condition and cash flow.

From time to time, legislation has been proposed that, if enacted into law, would make significant changes to U.S. federal and state income tax laws affecting the oil and natural gas industry, including (i) eliminating the immediate deduction for intangible drilling and development costs, (ii) the repeal of the percentage depletion allowance for oil and natural gas properties; and (iii) an extension of the amortization period for certain geological and geophysical expenditures. No accurate prediction can be made as to whether any such legislative changes will be proposed or enacted in the future or, if enacted, what the specific provisions or the effective date of any such legislation would be. These proposed changes in the U.S. tax law, if adopted, or other similar changes that would impose additional tax on our activities or reduce or eliminate deductions currently available with respect to natural gas and oil exploration, development or similar activities, could adversely affect our business, results of operations, financial condition and cash flow.

If third party pipelines or other facilities interconnected to Rattler LLC's midstream systems become partially or fully unavailable, or if the volumes we gather or treat do not meet the quality requirements of such pipelines or facilities, our midstream operations could be adversely affected.

Our subsidiary Rattler LLC's midstream systems are connected to other pipelines or facilities, the majority of which are owned by third parties. The continuing operation of such third party pipelines or facilities is not within our control. If any of these pipelines or facilities becomes unable to transport, treat or process natural gas or crude oil, or if the volumes we gather or transport do not meet the quality requirements of such pipelines or facilities, our midstream operations could be adversely affected.

We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our assets.

Our operations and drilling activity are concentrated in the Permian Basin in West Texas, an area in which industry activity has increased rapidly. As a result, demand for qualified personnel in this area, and the cost to attract and retain such personnel, has increased over the past few years due to competition and may increase substantially in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development activities could lead to a reduction in production volumes. Any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our business, financial condition and results of operations.

We rely on a few key employees whose absence or loss could adversely affect our business.

Many key responsibilities within our business have been assigned to a small number of employees. The loss of their services could adversely affect our business. In particular, the loss of the services of one or more members of our executive team, including our Chief Executive Officer, Travis D. Stice, could disrupt our operations. We do not have employment agreements with our executives and may not be able to assure their retention. Further, we do not maintain "key person" life insurance policies on any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including; unusual or unexpected geological formations; loss of drilling fluid circulation; title problems; facility or equipment malfunctions; unexpected operational events; shortages or delivery delays of equipment and services; compliance with environmental and other governmental requirements; and adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

Historically, we have acquired significant amounts of unproved property in order to further our development efforts and expect to continue to undertake acquisitions in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our earnings over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, gas leaks and ruptures or discharges of toxic gases. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigations and penalties, suspension of operations and repairs required to resume operations.

We endeavor to contractually allocate potential liabilities and risks between us and the parties that provide us with services and goods, which include pressure pumping and hydraulic fracturing, drilling and cementing services and tubular goods for surface, intermediate and production casing. Under our agreements with our vendors, to the extent responsibility for environmental liability is allocated between the parties, (i) our vendors generally assume all responsibility for control and removal of pollution or contamination which originates above the surface of the land and is directly associated with such vendors' equipment while in their control and (ii) we generally assume the responsibility for control and removal of all other pollution or contamination which may occur during our operations, including pre-existing pollution and pollution which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas or other substances, as well as the use or disposition of all drilling fluids. In addition, we generally agree to indemnify our vendors for loss or destruction of vendor-owned property that occurs in the well hole (except for damage that occurs when a vendor is performing work on a footage, rather than day work, basis) or as a result of the use of equipment, certain corrosive fluids, additives, chemicals or proppants. However, despite this general allocation of risk, we might not succeed in enforcing such contractual allocation, might incur an unforeseen liability falling outside the scope of such allocation or may be required to enter into contractual arrangements with terms that vary from the above allocations of risk. As a result, we may incur substantial losses which could materially and adversely affect our financial condition and results of operations.

In accordance with what we believe to be customary industry practice, we historically have maintained insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flow. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are part of our operations, we maintain insurance to protect against claims made for bodily injury and property damage, and that insurance includes coverage for clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the "occurrence" to our insurance company within the time frame required under our insurance policy. We have limited coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, our drilling activities may not be successful or economical.

We may not be able to keep pace with technological developments in our industry.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or may be forced by competitive pressures to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete, our business, financial condition or results of operations could be materially and adversely affected.

We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report material weaknesses in internal control over financial reporting, our investors may lose confidence in our reported information and our stock price may be negatively affected.

We are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley Act. Section 404 requires that we document and test our internal control over financial reporting and issue management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm opine on those internal controls. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify and report material weaknesses in internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

Increased costs of capital could adversely affect our business.

Our business could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our activities. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and cash flows.

The results of the 2020 U.S. presidential and congressional elections may create regulatory uncertainty for the oil and natural gas industry. Changes in environmental laws could increase our operating costs and adversely impact our business, financial condition and cash flows.

The results of the 2020 U.S. presidential election, as well as a closely divided Congress, may create regulatory uncertainty in the oil and natural gas industry. During his first weeks in office, President Biden has issued several executive orders promoting various programs and initiatives designed to, among other things, curtail climate change, control the release of methane from new and existing oil and natural gas operations, and pause new oil and natural gas leasing on public lands. It remains unclear what additional actions President Biden will take and what support he will have for any potential legislative changes from Congress. Further, it is uncertain to what extent any new environmental laws or regulations, or any repeal of existing environmental laws or regulations, may affect our business or operations. However, such actions could significantly increase our operating costs or impair our ability to explore and develop other projects, which could adversely impact our business, financial condition and cash flows.

Our operations depend heavily on electrical power, internet and telecommunication infrastructure and information and computer systems. If any of these systems are compromised or unavailable, our business could be adversely affected.

We are heavily dependent on electrical power, internet and telecommunications infrastructure and our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such infrastructure, systems or programs were to fail or become unavailable or compromised, or create erroneous information in our hardware or software network infrastructure, our ability to safely and effectively operate our business will be limited and any such consequence could have a material adverse effect on our business.

A terrorist attack or armed conflict could harm our business.

Terrorist activities, anti-terrorist efforts and other armed conflicts involving the United States or other countries may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas causing a reduction in our revenues. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if infrastructure integral to our customers' operations is destroyed or damaged. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, and processing activities. For example, the oil and natural gas industry depends on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering systems, conduct reservoir modeling and reserves estimation, and process and record financial and operating data. At the same time, cyber incidents, including deliberate attacks or unintentional events, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems, networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. We maintain specialized insurance for possible liability resulting from a cyberattack on our assets, however, we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Risks Related to Our Indebtedness

References in this section to "us," "we" or "our" shall mean Diamondback Energy, Inc. and Diamondback O&G LLC, collectively, unless otherwise specified.

We have relied in the past, and we may rely from time to time in the future, on borrowings under our revolving credit facility to fund a portion of our capital expenditures. Unless we are able to repay borrowings under the revolving credit facility with cash flow from operations and proceeds from equity or debt offerings, implementing our capital programs may require an increase in our total leverage through additional debt issuances. In addition, a reduction in availability under our revolving credit facility and the inability to otherwise obtain financing for our capital programs could require us to curtail our capital expenditures.

We have historically relied on availability under our revolving credit facility to fund a portion of our capital expenditures. We expect that we will continue to fund a portion of our capital expenditures with borrowings under the revolving credit facility, cash flow from operations and the proceeds from debt and equity offerings. In the past, we have created availability under the revolving credit facility by repaying outstanding borrowings with the proceeds from debt or equity offerings. We cannot assure you that we will choose to or be able to access the capital markets to repay any such future borrowings. Instead, we may be required or choose to finance our capital expenditures through additional debt issuances, which would increase our total amount of debt outstanding. If the availability under the revolving credit facility were reduced, and we were otherwise unable to secure other sources of financing, we may be required to curtail our capital expenditures, which could limit our ability to fund our drilling activities and acquisitions or otherwise finance the capital expenditures necessary to replace our reserves.

Our substantial level of indebtedness could adversely affect our financial condition and prevent us from fulfilling our obligations under our indebtedness.

As of December 31, 2020, we had total consolidated outstanding principal indebtedness of $5.8 billion, including $4.6 billion outstanding under our senior notes and $23 million outstanding under our revolving credit facility, and we had $1.98 billion available for borrowing under our revolving credit facility. As of December 31, 2020, Viper LLC, one of our subsidiaries, had $84 million in outstanding borrowings, and $496 million available for borrowing, under its revolving credit facility and $480 million outstanding under its 5.375% Senior Notes due 2027. As of December 31, 2020, Rattler LLC, one of our subsidiaries, had $79 million in outstanding borrowings, and $521 million available for borrowing, under its revolving credit facility and $500 million outstanding under its 5.625% Senior Notes due 2025.

We may in the future incur significant additional indebtedness under our revolving credit facility or otherwise in order to make acquisitions, to develop our properties or for other purposes. Our level of indebtedness could have important consequences to you and affect our operations in several ways, including the following: our high level of indebtedness could make it more difficult for us to satisfy our obligations with respect to our debt instruments, including any repurchase obligations that may arise thereunder; a significant portion of our cash flows could be used to service our indebtedness, which could reduce the funds available to us for operations and other purposes; our high level of debt could increase our vulnerability to general adverse economic and industry conditions; the covenants contained in the agreements governing certain of our outstanding indebtedness will limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments; our high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing; our debt covenants may also limit management's discretion in operating our business and our flexibility in planning for, and reacting to, changes in the economy and in our industry; our high level of debt could limit our ability to access the capital markets to raise capital on favorable terms; our high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and we may be vulnerable to interest rate increases, as our borrowings under our revolving credit facility are at variable interest rates.

We may still be able to incur substantial additional indebtedness in the future, which could further exacerbate the risks that we and our subsidies face.

Restrictive covenants in certain of our existing and future debt instruments may limit our ability to respond to changes in market conditions or pursue business opportunities.

Certain of our debt instruments contain, and the terms of any future indebtedness may contain, restrictive covenants that limit our ability to, among other things: incur or guarantee additional indebtedness; make certain investments; create liens; sell or transfer assets; issue preferred stock; merge or consolidate with another entity; pay dividends or make other distributions; create unrestricted subsidiaries; and engage in transactions with affiliates.

Under our revolving credit facility we are allowed, among other things, to designate one or more of our subsidiaries as “unrestricted subsidiaries” that are not subject to certain restrictions contained in the revolving credit facility. Under our revolving credit facility, we designated Viper, Viper’s general partner, Viper’s subsidiary, Rattler, Rattler’s general partner and Rattler’s subsidiaries as unrestricted subsidiaries, and upon such designation, they were automatically released from any and all obligations under the revolving credit facility, including the related guaranty. Further Viper, Viper’s general partner, Viper’s subsidiaries, Rattler, Rattler’s general partner and Rattler’s subsidiaries are designated as unrestricted subsidiaries under the indentures governing our outstanding senior notes.

We and our subsidiaries may be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants and financial covenants contained in our and our subsidiaries’ debt instruments. As an example, our revolving credit facility requires us to maintain a total net debt to capitalization ratio. The requirement that we and our subsidiaries comply with these provisions may materially adversely affect our and our subsidiaries ability to react to changes in market conditions, take advantage of business opportunities we believe to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in our business.

A breach of any of these restrictive covenants could result in default under the applicable debt instrument. If default occurs under our revolving credit facility, the lenders thereunder may elect to declare all borrowings outstanding, together with accrued interest and other fees, to be immediately due and payable, which would result in an event of default under the indentures governing our senior notes. The lenders will also have the right in these circumstances to terminate any commitments they have to provide further borrowings. If the indebtedness under our revolving credit facility and our senior notes were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full that indebtedness.

Our indebtedness is structurally subordinated to the indebtedness and other liabilities of our subsidiaries, and our obligations are not obligations of any of our subsidiaries.

Our senior indebtedness obligations are obligations exclusively of Diamondback Energy, Inc. and Diamondback O&G LLC, and not of any of our other subsidiaries. None of our subsidiaries is a guarantor of our senior indebtedness. Any assets of our subsidiaries will not be directly available to satisfy the claims of our creditors, including lenders under our revolving credit facility and holders of the senior notes. Except to the extent we are a creditor with recognized claims against our subsidiaries, all claims of creditors of our subsidiaries will have priority over our equity interests in such subsidiaries (and therefore the claims of our creditors, including lenders under our revolving credit facility and holders of the senior notes) with respect to the assets of such subsidiaries. Even if we are recognized as a creditor of one or more of our subsidiaries, our claims would still be effectively subordinated to any security interests in the assets of any such subsidiary and to any indebtedness or other liabilities of any such subsidiary senior to our claims. Consequently, our senior indebtedness will be structurally subordinated to all indebtedness and other liabilities of any of our subsidiaries and any subsidiaries that we may in the future acquire or establish. For additional information regarding our subsidiaries outstanding debt as of December 31, 2020, see Note 11—Debt to our consolidated financial statements included elsewhere in this report.

Servicing our indebtedness requires a significant amount of cash, and we may not have sufficient cash flow from our business to pay our substantial indebtedness.

Our ability to make scheduled payments of the principal, to pay interest on or to refinance our indebtedness, including our senior notes, depends on our future performance, which is subject to economic, financial, competitive and other factors beyond our control. Our business may not generate cash flow from operations in the future sufficient to service our debt and make necessary capital expenditures. If we are unable to generate such cash flow, we may be required to adopt one or more alternatives, such as reducing or delaying capital expenditures, selling assets, restructuring debt or obtaining additional equity capital on terms that may be onerous or highly dilutive. However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. In the absence of such cash flows, we could have substantial liquidity problems and might be required to sell material assets or operations to attempt to meet our debt service and other obligations. The indenture governing the 2025 Senior Notes restricts our ability to use the proceeds from asset sales. We may not be able to consummate those asset sales to raise capital or sell assets at prices that we believe are fair, and proceeds that we do receive may not be adequate to meet any debt service obligations then due. Our ability to refinance our indebtedness will depend on the capital markets and our financial condition at the time. We may not be able to engage in any of these activities or engage in these activities on desirable terms, which could result in a default on our debt obligations and have an adverse effect on our financial condition.

We depend on our subsidiaries for dividends, distributions and other payments.

We depend on our subsidiaries for dividends, distributions and other payments. We are a legal entity separate and distinct from our operating subsidiaries. There are statutory and regulatory limitations on the payment of dividends or distributions by certain of our subsidiaries to us. If our subsidiaries are unable to make dividend or distribution payments to us and sufficient cash or liquidity is not otherwise available, we may not be able to make dividend payments to our stockholders or principal and interest payments on our outstanding indebtedness.

We and our subsidiaries may still be able to incur substantial additional indebtedness in the future, which could further exacerbate the risks that we and our subsidiaries face.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future. The terms of our and our subsidiaries' revolving credit facilities and the indentures restrict, but in each case do not completely prohibit, us from doing so. Further, the indentures governing our and our subsidiaries' notes allow us to issue additional notes, incur certain other additional debt and to have subsidiaries that do not guarantee the senior notes and which may incur additional debt, which would be structurally senior to the senior notes. In addition, the indentures governing the senior notes do not prevent us from incurring other liabilities that do not constitute indebtedness. If we or a guarantor incur any additional indebtedness that ranks equally with the senior notes (or with the guarantees thereof), including additional unsecured indebtedness or trade payables, the holders of that indebtedness will be entitled to share ratably with holders of the senior notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us or a guarantor. If new debt or other liabilities are added to our current debt levels, the related risks that we and our subsidiaries now face could intensify.

If we experience liquidity concerns, we could face a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit and increase our borrowing costs.

Borrowings under our, Viper LLC's and Rattler LLC's revolving credit facilities expose us to interest rate risk.

Our earnings are exposed to interest rate risk associated with borrowings under our and our subsidiaries' revolving credit facilities. The terms of our and our subsidiaries' revolving credit facilities provide for interest on borrowings at a floating rate equal to an alternate base rate tied to LIBOR. LIBOR tends to fluctuate based on multiple facts, including general short-term interest rates, rates set by the U.S. Federal Reserve and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. We use interest rate swaps to reduce interest rate exposure with respect to our floating rate debt. Our weighted average interest rate on borrowings under our revolving credit facility was 2.02% during the year ended December 31, 2020. Viper LLC's weighted average interest rate on borrowings from its revolving credit facility was 2.20% during the year ended December 31, 2020. Rattler LLC's weighted average interest rate on borrowings from its revolving credit facility was 2.10% during the year ended December 31, 2020. If interest rates increase, so will our interest costs, which may have a material adverse effect on our results of operations and financial condition.

On July 27, 2017, the U.K. Financial Conduct Authority (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021. It is unclear whether new methods of calculating LIBOR will be established or if LIBOR will continue to exist after 2021. The U.S. Federal Reserve, in conjunction with the Alternative Reference Rates Committee, is considering replacing U.S. dollar LIBOR with a newly created index. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United States or elsewhere.

Risks Related to Our Common Stock

The corporate opportunity provisions in our certificate of incorporation could enable affiliates of ours to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our certificate of incorporation, among other things; permits us to enter into transactions with entities in which one or more of our officers or directors are financially or otherwise interested; permits any of our stockholders, officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and provides that if any director or officer of one of our affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter (other than one expressly offered to that director or officer in writing solely in his or her capacity as our director or officer), that director or officer will have no duty to communicate or offer that opportunity to us, and will be permitted to communicate or offer that opportunity to such affiliates and that director or officer will not be deemed to have (i) acted in a manner inconsistent with his or her fiduciary or other duties to us regarding the opportunity or (ii) acted in bad faith or in a manner inconsistent with our best interests.

These provisions create the possibility that a corporate opportunity that would otherwise be available to us may be used for the benefit of one of our affiliates.

We have engaged in the past and may in the future engage in transactions with our affiliates. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests.

In the past, we have engaged in transactions with affiliated companies and may do so again in the future. These transactions, and the resolution of any conflicts that may arise in connection with such related party transactions, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests.

If the price of our common stock fluctuates significantly, your investment could lose value.

Although our common stock is listed on the Nasdaq Global Select Market, we cannot assure you that an active public market will continue for our common stock. If an active public market for our common stock does not continue, the trading price and liquidity of our common stock will be materially and adversely affected. If there is a thin trading market or "float" for our stock, the market price for our common stock may fluctuate significantly more than the stock market as a whole. Without a large float, our common stock would be less liquid than the stock of companies with broader public ownership and, as a result, the trading prices of our common stock may be more volatile. In addition, in the absence of an active public trading market, investors may be unable to liquidate their investment in us. Furthermore, the stock market is subject to significant price and volume fluctuations, and the price of our common stock could fluctuate widely in response to several factors, including; our quarterly or annual operating results; changes in our earnings estimates; investment recommendations by securities analysts following our business or our industry; additions or departures of key personnel; changes in the business, earnings estimates or market perceptions of our competitors; our failure to achieve operating results consistent with securities analysts' projections; changes in industry, general market or economic conditions; and announcements of legislative or regulatory changes.

The stock market has experienced extreme price and volume fluctuations in recent years that have significantly affected the quoted prices of the securities of many companies, including companies in our industry. The changes often appear to occur without regard to specific operating performance. The price of our common stock could fluctuate based upon factors that have little or nothing to do with our company and these fluctuations could materially reduce our stock price.

The declaration of dividends and any repurchases of our common stock are each within the discretion of our board of directors based upon a review of relevant considerations, and there is no guarantee that we will pay any dividends on or repurchase shares of our common stock in the future or at levels anticipated by our stockholders.

On February 13, 2018, we initiated payment of quarterly cash dividends on our common stock payable beginning with the first quarter of 2018. The decision to pay any future dividends, however, is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination. Based on its evaluation of these factors, the board of directors may determine not to declare a dividend, or declare dividends at rates that are less than currently anticipated, either of which could reduce returns to our stockholders.

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 at the discretion of our board of directors and may be suspended from time to time, modified, extended or discontinued by our board of directors at any time. The repurchase program was suspended beginning in the first quarter of 2020 and expired on December 31, 2020.

A change of control could limit our use of net operating losses.

As of December 31, 2020, we had a net operating loss, or NOL, carry forward of approximately $2.3 billion for federal income tax purposes. If we were to experience an "ownership change," as determined under Section 382 of the Code, our ability to offset taxable income arising after the ownership change with NOLs generated prior to the ownership change would be limited, possibly substantially. In general, an ownership change would establish an annual limitation on the amount of our pre-change NOLs that we could utilize to offset our taxable income in any future taxable year to an amount generally equal to the value of our stock immediately prior to the ownership change multiplied by an interest rate periodically promulgated by the IRS referred to as the long-term tax-exempt rate. In general, an ownership change will occur if there is a cumulative increase in the ownership of our stock totaling more than 50 percentage points by one or more "5% shareholders" (as defined in the Code) at any time during a rolling three-year period.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrade our stock or if our operating results do not meet their expectations, our stock price could decline.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

Provisions in our certificate of incorporation and bylaws and Delaware law make it more difficult to effect a change in control of the company, which could adversely affect the price of our common stock.

The existence of some provisions in our certificate of incorporation and bylaws and Delaware corporate law could delay or prevent a change in control of our company, even if that change would be beneficial to our stockholders. Our certificate of incorporation and bylaws contain provisions that may make acquiring control of our company difficult, including; provisions regulating the ability of our stockholders to nominate directors for election or to bring matters for action at annual meetings of our stockholders; limitations on the ability of our stockholders to call a special meeting and act by written consent; the ability of our board of directors to adopt, amend or repeal bylaws, and the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained for stockholders to amend our bylaws; the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to remove directors; the requirement that the affirmative vote of holders representing at least 66 2/3% of the voting power of all outstanding shares of capital stock be obtained to amend our certificate of incorporation; and the authorization given to our board of directors to issue and set the terms of preferred stock without the approval of our stockholders.

These provisions also could discourage proxy contests and make it more difficult for you and other stockholders to elect directors and take other corporate actions. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are a party to various legal proceedings, disputes and claims arising in the course of our business, including those that arise from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry, personal injury claims, title disputes, royalty disputes, contract claims, contamination claims relating to oil and natural gas exploration and development and environmental claims, including claims involving assets previously sold to third parties and no longer part of our current operations. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on us, cannot be predicted with certainty, we believe that none of these matters, if ultimately decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

For additional information regarding contingencies, see Note 17—Commitments and Contingencies included in notes to the consolidated financial statements included elsewhere in this Annual Report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Listing and Holders of Record

Our common stock is listed on the Nasdaq Global Select Market under the symbol "FANG". There were 2,564 holders of record of our common stock on February 19, 2021.

Dividend Policy

On February 13, 2018, we announced the initiation of an annual cash dividend in the amount of $0.50 per share of our common stock payable quarterly which began with the first quarter of 2018. Beginning with the first quarter of 2019, the annual cash dividend was set at $0.75 per share of our common stock. Then, beginning with the fourth quarter of 2019, the annual cash dividend was increased to $1.50 per share for our common stock and, beginning with the fourth quarter of 2020, the annual cash dividend was further increased to $1.60 per share of our common stock. The decision to pay any future dividends is solely within the discretion of, and subject to approval by, our board of directors. Our board of directors' determination with respect to any such dividends, including the record date, the payment date and the actual amount of the dividend, will depend upon our profitability and financial condition, contractual restrictions, restrictions imposed by applicable law and other factors that the board deems relevant at the time of such determination.

Unregistered Sales of Equity Securities

As previously disclosed in our Current Report on Form 8-K filed with the SEC on December 21, 2020, we entered into a definitive purchase and sale agreement, dated as of December 18, 2020, with Guidon and certain of Guidon's affiliates to acquire approximately 32,500 net acres in the Northern Midland Basin and certain related oil and gas assets. Consideration for the Pending Guidon Acquisition consists of $375 million in cash and 10.6 million shares of our common stock, subject to adjustment. The shares to be issued in the Pending Guidon Acquisition will be issued in reliance upon the exemption from the registration requirements of the Securities Act provided by Section 4(a)(2) of the Securities Act as sales by an issuer not involving any public offering. We have agreed to file with the SEC, and use our reasonable best efforts to cause to be declared effective, a shelf registration statement registering for resale these shares within 60 days following the closing of the Pending Guidon Acquisition, which is expected to occur on February 26, 2021.

Repurchases of Equity Securities

Our common stock repurchase activity for the three months ended December 31, 2020 was as follows:

Period	Total Number of Shares Purchased	Average Price Paid Per Share(1)	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan(2)
	($ in millions, except per share amounts, shares in thousands)			
October 1, 2020 - October 31, 2020	—	$ —	—	$ 1,304
November 1, 2020 - November 30, 2020	—	$ —	—	$ 1,304
December 1, 2020 - December 31, 2020	—	$ —	—	$ —
Total	—	$ —	—	

(1) The average price paid per share is net of any commissions paid to repurchase stock.
(2) 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 was suspended beginning in the first quarter of 2020 and expired on December 31, 2020.

ITEM 6. SELECTED FINANCIAL DATA

[Reserved.]

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our consolidated financial statements and notes thereto appearing elsewhere in this Annual Report. 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 Item 1A. "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We operate in two operating segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas and (ii) through our subsidiary, Rattler, the midstream operations segment, which is focused on ownership, operation, development and acquisition of the midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin.

Upstream Operations

In our upstream segment, 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.

As of December 31, 2020, we had approximately 378,678 net acres, which primarily consisted of approximately 194,591 net acres in the Midland Basin and approximately 152,587 net acres in the Delaware Basin. As of December 31, 2020, we had an estimated 10,413 gross horizontal locations that we believe to be economic at $60.00 per Bbl WTI.

In addition, our publicly traded subsidiary Viper owns mineral interests underlying approximately 787,264 gross acres and 24,350 net royalty acres in the Permian Basin and Eagle Ford Shale. Approximately 52% of these net royalty acres are operated by us.

Midstream Operations

In our midstream operations segment, Rattler's crude oil infrastructure assets consist of gathering pipelines and metering facilities, which collectively gather crude oil for its customers. Rattler's facilities gather crude oil from horizontal and vertical wells in our ReWard, Spanish Trail, Pecos and Fivestones areas within the Permian Basin. Rattler's natural gas gathering and compression system consists of gathering pipelines, compression and metering facilities, which collectively service the production from our Pecos area assets within the Permian Basin. Rattler's water sourcing and distribution assets consists of water wells, frac pits, pipelines and water treatment facilities, which collectively gather and distribute water from Permian Basin aquifers to the drilling and completion sites through buried pipelines and temporary surface pipelines. Rattler's gathering and disposal system spans approximately 517 miles and consists of gathering pipelines along with produced water disposal, or PWD, wells and facilities which collectively gather and dispose of produced water from operations throughout our Permian Basin acreage.

We have entered into multiple fee-based commercial agreements with Rattler, each with an initial term ending in 2034, utilizing Rattler's infrastructure assets or its planned infrastructure assets to provide an array of essential services critical to our upstream operations in the Delaware and Midland Basins. Our agreements with Rattler include substantial acreage dedications.

2020 Transactions and Recent Developments

COVID-19 and Collapse in Commodity Prices

On March 11, 2020, the World Health Organization characterized the global outbreak of the novel strain of coronavirus, COVID-19, as a "pandemic." To limit the spread of COVID-19, governments have taken various actions including the issuance of stay-at-home orders and social distancing guidelines, causing some businesses to suspend operations and a reduction in demand for many products from direct or ultimate customers. Although many stay-at-home orders have expired and certain restrictions on conducting business have been lifted, the COVID-19 pandemic resulted in a widespread health crisis and a swift and unprecedented reduction in international and U.S. economic activity which, in turn, has adversely affected the demand for oil and natural gas and caused significant volatility and disruption of the financial markets.

In early March 2020, oil prices dropped sharply and continued to decline reaching negative levels. During 2020, the posted price for the WTI price for crude oil ranged from $(37.63) to $63.27 per barrel, or Bbl, and the NYMEX Henry Hub price of natural gas ranged from $1.48 to $3.35 per MMBtu. On January 29, 2021, the NYMEX WTI price for crude oil was $52.20 per Bbl and the NYMEX Henry Hub price of natural gas was $2.56 per MMBtu. In response to recent volatility in commodity prices, many producers have reduced their capital expenditure budgets. This was a result of multiple factors affecting the supply and demand in global oil and natural gas markets, including actions taken by OPEC members and other exporting nations impacting commodity price and production levels and a significant decrease in demand due to the ongoing COVID-19 pandemic. While OPEC members and certain other nations agreed in April 2020 to cut production and subsequently extended such production cuts through December 2020, which helped to reduce a portion of the excess supply in the market and improve crude oil prices, they agreed to increase production by 500,000 barrels per day beginning in January 2021. We cannot predict if or when commodity prices will stabilize and at what levels.

As a result of the reduction in crude oil demand caused by factors discussed above, in 2020, we lowered our 2020 capital budgets and production guidance, curtailed near term production and reduced rig count, all of which may be subject to further reductions or curtailment if the commodity markets and macroeconomic conditions worsen. Although we have restored curtailed production, actions taken in response to the COVID-19 pandemic and depressed commodity pricing environment have had and are expected to continue to have an adverse effect on our business, financial results and cash flows.

In addition, as a result of the sharp decline in commodity prices in early March 2020, and the continued depressed oil pricing throughout the second and third quarters of 2020, we recorded $6.0 billion of aggregate non-cash ceiling test impairments for the year ended December 31, 2020. These impairment charges adversely affected our results of operations but did not reduce our cash flows. If the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters, we will have material write downs in subsequent quarters. Our production, proved reserves and cash flows will also be adversely impacted. Our results of operations may be further adversely impacted by any government rule, regulation or order that may impose production limits, as well as pipeline capacity and storage constraints, in the Permian Basin where we operate.

Given the dynamic nature of these events, we cannot reasonably estimate the period of time that the COVID-19 pandemic, the depressed commodity prices and the adverse macroeconomic conditions will persist, the full extent of the impact they will have on our industry and our business, financial condition, results of operations or cash flows, or the pace or extent of any subsequent recovery.

Pending Merger with QEP Resources, Inc.

On December 20, 2020, we, QEP and the Merger Sub, entered into the merger agreement under which the Merger Sub will be merged with and into QEP, with QEP surviving as our wholly owned subsidiary. If the pending merger is completed, each QEP stockholder will receive, in exchange for each share of QEP common stock held by such stockholder immediately prior to the closing of the pending merger, 0.050 of a share of our common stock. The completion of the pending merger is subject to satisfaction or waiver of certain customary mutual closing conditions, including the receipt of the required approvals from QEP's stockholders. The pending merger is expected to close shortly following the special meeting of the QEP stockholders, which is scheduled for March 16, 2021, subject to QEP stockholder approval and other customary closing conditions. See "Items 1 and 2. Business and Properties—Overview—Pending Merger with QEP Resources, Inc." for additional information regarding the pending merger.

We expect that the pending merger will:

- add material Tier-1 Midland Basin inventory;
- be accretive on all relevant 2021 per share metrics including cash flow per share, free cash flow per share and leverage, before accounting for synergies;
- lower 2021 reinvestment ratio and enhance ability to generate free cash flow, de-lever and return capital to our stockholders; and
- realize significant, tangible annual synergies of $60 to $80 million comprised of general and administrative expense savings, cost of capital and interest expense savings, improved capital efficiency from high-graded development of

combined acreage, physical adjacencies to increase lateral lengths and significant adjacent Permian Basin midstream assets.

In addition, we expect to maintain our investment grade credit ratings following the completion of the pending merger.

Pending Guidon Acquisition

On December 18, 2020, we entered into a definitive purchase and sale agreement with Guidon and certain of Guidon's affiliates to acquire approximately 32,500 net acres in the Northern Midland Basin and certain related oil and natural gas assets, which we refer to as the Pending Guidon Acquisition. Consideration for the Pending Guidon Acquisition consists of $375 million in cash and 10.6 million shares of our common stock, subject to adjustment. The cash portion of this transaction is expected to be funded through a combination of cash on hand and borrowings under our credit facility. The Pending Guidon Acquisition is expected to close on February 26, 2021.

Fourth Quarter 2020 Dividend Declaration and Increase

On February 18, 2021, our board of directors declared a cash dividend for the fourth quarter of 2020 of $0.40 per share of common stock, payable on March 11, 2021 to our stockholders of record at the close of business on March 4, 2021, representing a 6.7% increase per share from the previously paid quarterly dividend.

Implementation of Viper's Common Unit Repurchase Program

On November 6, 2020, the board of directors of Viper's general partner approved an expansion of Viper's return of capital program with the implementation of a common unit repurchase program to acquire up to $100 million of Viper's outstanding common units through December 31, 2021. During the year ended December 31, 2020, Viper repurchased approximately $24 million of its common units under its repurchase program. As of December 31, 2020, $76 million remained available for use to repurchase common units under Viper's common unit repurchase program.

Implementation of Rattler's Common Unit Repurchase Program

On October 29, 2020, the board of directors of Rattler's general partner approved a common unit repurchase program to acquire up to $100 million of Rattler's outstanding common units through December 31, 2021. During the year ended December 31, 2020, Rattler repurchased approximately $15 million of its common stock under its repurchase program. As of December 31, 2020, $85 million remained available for use to repurchase common units under Rattler's common unit repurchase program.

May 2020 Notes Offering

On May 26, 2020, we completed a notes offering of $500 million in aggregate principal amount of our 4.750% Senior Notes due 2025, which we refer to as the May 2020 Notes. We received net proceeds of approximately $496 million from the offering of the May 2020 Notes which we used to, among other things, make an equity contribution to Energen to purchase $209 million in aggregate principal amount of Energen's 4.625% senior notes pursuant to a tender offer. For additional information regarding this notes offering, see "—Liquidity and Capital Resources—Indebtedness—The May 2020 Notes and Tender Offer for Energen's 4.625% Senior Notes and Repurchase of Energen's 7.35% Medium-term Notes" below.

Rattler Notes Offering

On July 14, 2020, Rattler completed an offering, which we refer to as the Rattler Notes Offering, of its 5.625% senior notes due 2025 in the aggregate principal amount of $500 million, which we refer to as the Rattler Notes. Rattler received net proceeds of approximately $490 million from the Rattler Notes Offering and loaned the gross proceeds of the Rattler Notes Offering to Rattler LLC to pay down borrowings under its revolving credit facility. For additional information regarding the Rattler Notes Offering, see "—Liquidity and Capital Resources—Indebtedness—Rattler's Notes" below.

Operational Update

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.

As of December 31, 2020, we were operating eight drilling rigs and currently intend to operate between eight and 12 drilling rigs in 2021 on average across our current acreage position in the Midland and Delaware Basins.

In the Midland Basin, we continued to have positive results across our core development areas located within Midland, Martin, Howard, Glasscock and Andrews counties, where development has primarily focused on drilling long-lateral, multi-well pads targeting the Spraberry and Wolfcamp formations.

In the Delaware Basin, we have now drilled and completed a significant number of wells in Pecos, Reeves and Ward counties targeting the Wolfcamp A, which we believe has been de-risked across a significant portion of our total acreage position and remains our primary development target. In 2021, we expect to focus development on these areas.

In the fourth quarter of 2020, we executed on our business strategy, providing a foundation for continued solid operational performance in 2021. We are starting to see the benefits from our strategy to cut activity and high-grade development focusing on our most productive areas in terms of capital efficiency and early-time well performance. While the impact of the recent winter storms in the Permian Basin on the first quarter 2021 production is expected to be significant (ranging from four to five days of total net production lost), we expect to overcome this adverse impact for the full year 2021. Well costs and cash operating costs remain near all-time lows, providing for increased returns to our stockholders as commodity prices have risen in recent months. In 2021, we intend to continue to focus on low cost operations and best in class execution and currently plan to hold our fourth quarter 2020 production flat while generating free cash flow used to pay dividends and pay down debt. To combat potential fluctuation in service costs, we have worked to implement new and more efficient drilling and completions methodologies and will continue to seek opportunities to control additional well cost where possible. Our 2021 drilling and completion budget accounts for capital costs that we expect to occur during the year.

In 2021, we remain focused on navigating our industry challenges by staying disciplined, improving our industry-leading cost structure, maintaining production and increasing environmental transparency.

Environmental Responsibility Initiatives and Highlights

In February 2021, we announced significant enhancements to our commitment to environmental, social responsibility and governance, or ESG, performance and disclosure, including Scope 1 and methane emission intensity reduction targets. Our goals include the reduction of our Scope 1 greenhouse gas intensity by at least 50% and methane intensity by at least 70%, in each case by 2024 from the 2019 levels. To further underscore our commitment to carbon neutrality, we are also implementing our “Net Zero Now” initiative under which, effective January 1, 2021, every hydrocarbon molecule we produce is anticipated to be produced with zero Scope 1 emissions. To the extent our greenhouse gas and methane intensity targets do not eliminate our carbon footprint, we intend to purchase carbon credits to offset the remaining emissions. We also plan to increase the weighting of ESG metrics in our annual short-term incentive compensation plan to motivate our executives to advance our environmental responsibility goals.

With respect to flaring, we flared 0.9% of our gross natural gas production in the fourth quarter of 2020. For the full year ended 2020, we flared 2.0% of our gross natural gas production, down 64% from 2019.

2021 Capital Budget

We have currently budgeted 2021 total capital spend of $1.4 billion to $1.6 billion, consisting of $1.2 billion to $1.4 billion for horizontal drilling and completions including non-operated activity, $60 million to $80 million for midstream investments, excluding joint venture investments, and $70 million to $90 million for infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions. We expect to drill and complete 215 to 235 gross horizontal wells in 2021. Should commodity prices weaken, we intend to act responsibly and, consistent with our prior practices, reduce capital spending. If commodity prices strengthen, we intend to grow oil production within our 2021 budget, pay down indebtedness and return cash to our stockholders.

Results of Operations

For a discussion of the results of operations for the year ended December 31, 2019 as compared to the year ended December 31, 2018, please refer to "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2019 (filed with the SEC on February 27, 2020), which discussion is incorporated in this report by reference from such prior report on Form 10-K. The following table sets forth selected historical operating data for the periods indicated:

	Year Ended December 31,	
	2020	2019
Revenues (in millions):		
Oil sales	$ 2,410	$ 3,554
Natural gas sales	107	66
Natural gas liquid sales	239	267
Total oil, natural gas and natural gas liquid revenues	$ 2,756	$ 3,887
Production Data (in thousands):		
Oil (MBbls)	66,182	68,518
Natural gas (MMcf)	130,549	97,613
Natural gas liquids (MBbls)	21,981	18,498
Combined volumes (MBOE)	109,921	103,285
Daily oil volumes (BO/d)	180,825	187,721
Daily combined volumes (BOE/d)	300,331	282,972
Average Prices:		
Oil ($ per Bbl)	$ 36.41	$ 51.87
Natural gas ($ per Mcf)	$ 0.82	$ 0.68
Natural gas liquids ($ per Bbl)	$ 10.87	$ 14.42
Combined ($ per BOE)	$ 25.07	$ 37.63
Oil, hedged ($ per Bbl)(1)	$ 40.34	$ 51.96
Natural gas, hedged ($ per MMbtu)(1)	$ 0.67	$ 0.86
Natural gas liquids, hedged ($ per Bbl)(1)	$ 10.83	$ 15.20
Average price, hedged ($ per BOE)(1)	$ 27.26	$ 38.00

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices and include gains and losses on cash settlements for matured commodity derivatives, which we do not designate for hedge accounting. Hedged prices exclude gains or losses resulting from the early settlement of commodity derivative contracts.

Production Data

Substantially all of our revenues are generated through the sale of oil, natural gas and natural gas liquids production. The following tables set forth our production data for the years ended December 31, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
Oil (MBbls)	60 %	66 %
Natural gas (MMcf)	20 %	16 %
Natural gas liquids (MBbls)	20 %	18 %
	100 %	100 %

Comparison of the Years Ended December 31, 2020 and 2019

Oil, Natural Gas and Natural Gas Liquids Revenues. Our revenues are a function of oil, natural gas and natural gas liquids production volumes sold and average sales prices received for those volumes.

The net dollar effect of the change in prices are shown below:

	Change in prices	Production volumes(1)	Total net dollar effect of change
			(in millions)
Effect of changes in price:			
Oil	$ (15.46)	66,182	$ (1,023)
Natural gas	$ 0.14	130,549	$ 18
Natural gas liquids	$ (3.55)	21,981	$ (77)
Total revenues due to change in price			$ (1,082)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change
			(in millions)
Effect of changes in production volumes:			
Oil	(2,336)	$ 51.87	$ (121)
Natural gas	32,936	$ 0.68	$ 22
Natural gas liquids	3,483	$ 14.42	$ 50
Total change in revenues			$ (49)
			$ (1,131)

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

Our oil, natural gas and natural gas liquids revenues decreased by approximately $1.1 billion, or 29%, to $2.8 billion for the year ended December 31, 2020 from $3.9 billion for the year ended December 31, 2019, largely attributable to lower oil average sales prices resulting from the impact of the COVID-19 pandemic and other volatility in global commodity prices as discussed in "—COVID-19 and collapse in Commodity Prices" above.

Average daily production sold increased by 17,359 BOE/d to 300,331 BOE/d during the year ended December 31, 2020 from 282,972 BOE/d during the year ended December 31, 2019, primarily due to an increase in natural gas liquids and natural gas production, which was partially offset by temporarily curtailing a portion of our oil production volumes during 2020 in response to the sudden drop in demand and prices for oil stemming from the COVID-19 pandemic.

Midstream Services Revenue. The following table shows midstream services revenue for the years ended December 31, 2020 and 2019:

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in millions)	
Midstream services	$ 50	$ 64

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. Midstream services revenue decreased by $14 million for the year ended December 31, 2020 as compared to the year ended December 31, 2019 primarily due to a reduction in sourced water volumes due to the lower level of drilling and completion activity in 2020.

Lease Operating Expenses. The following table shows lease operating expenses for the years ended December 31, 2020 and 2019:

	Year Ended December 31,			
	2020		2019	
(in millions, except per BOE amounts)	Amount	Per BOE	Amount	Per BOE
Lease operating expenses	$ 425	$ 3.87	$ 490	$ 4.74

Lease operating expenses for the year ended December 31, 2020 as compared to the year ended December 31, 2019 decreased by $65 million, or $0.87 per BOE. Lease operating expenses decreased due to a reduction in work over and well maintenance activity through overall efficiencies gained, as well as improvements in infrastructure which reduced power generation costs and trucking fees. In addition to these efficiencies we have seen a reduction in service pricing in 2020, driven by the reduction in current industry activity levels. We expect service pricing may increase in future periods, particularly if current industry activity levels increase.

Production and Ad Valorem Tax Expense. The following table shows production and ad valorem tax expense for the years ended December 31, 2020 and 2019:

	Year Ended December 31,			
	2020		2019	
(in millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Production taxes	$ 135	$ 1.23	$ 184	$ 1.78
Ad valorem taxes	60	0.54	64	0.62
Total production and ad valorem expense	$ 195	$ 1.77	$ 248	$ 2.40
Production taxes as a % of oil, natural gas, and natural gas liquids revenue	4.9 %		4.7 %	

In general, production taxes are directly related to production revenues and are based upon current year commodity prices. Production taxes for the year ended December 31, 2020 as compared to the year ended December 31, 2019 decreased by $49 million, or $0.55 per BOE, due to current year commodity prices. Production taxes as a percentage of production revenues remained consistent for the year ended December 31, 2020 compared to the year ended December 31, 2019.

Gathering and Transportation Expense. The following table shows gathering and transportation expense for the year ended December 31, 2020 and 2019:

	Year Ended December 31,			
	2020		2019	
(in millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
Gathering and transportation expense	$ 140	$ 1.27	$ 88	$ 0.86

For the year ended December 31, 2020, the per BOE increases for gathering and transportation expenses are primarily attributable to recording minimum volume commitment fees in 2020, as well as an increase in fees for our gas production and an overall change in our product mix, with gas and natural gas liquids production becoming a greater percentage of overall production.

Midstream Services Expense. The following table shows midstream services expense for the years ended December 31, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
	(in millions)	
Midstream services expense	$ 105	$ 91

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. Midstream services expense for the year ended December 31, 2020 as compared to the year ended December 31, 2019 increased by $14 million primarily due to increased volume and build out of the Rattler systems.

Depreciation, Depletion and Amortization. The following table provides the components of our depreciation, depletion and amortization expense for the years ended December 31, 2020 and 2019:

(in millions, except BOE amounts)	**Year Ended December 31, 2020**	**2019**
Depletion of proved oil and natural gas properties	$ 1,242	$ 1,398
Depreciation of midstream assets	44	33
Depreciation of other property and equipment	18	16
Depreciation, depletion and amortization expense	$ 1,304	$ 1,447
Oil and natural gas properties depletion per BOE	$ 11.30	$ 13.54

The decrease in depletion of proved oil and natural gas properties of $156 million for the year ended December 31, 2020 as compared to the year ended December 31, 2019 resulted primarily from a reduction in the average depletion rate for our oil and natural gas properties in 2020, which stemmed from a decrease in the net book value of our properties due to the full cost ceiling impairments recorded in the first three quarters of 2020 as well as lower production levels in 2020 as compared to 2019.

Impairment of Oil and Natural Gas Properties. As a result of the decline in commodity prices during 2020 and 2019, we recorded non-cash ceiling test impairments for the years ended December 31, 2020 and 2019 of $6.0 billion and $790 million, respectively, which is included in accumulated depletion, depreciation, amortization and impairment on our consolidated balance sheet. The impairment charges affected our results of operations but did not reduce cash flow. In addition to commodity prices, our production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine our actual ceiling test calculation and impairment analysis in future periods. If the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters, we will continue to have material write-downs in subsequent quarters.

General and Administrative Expenses. The following table shows general and administrative expenses for the years ended December 31, 2020 and 2019:

	Year Ended December 31,			
	2020		**2019**	
(in millions, except per BOE amounts)	**Amount**	**Per BOE**	**Amount**	**Per BOE**
General and administrative expenses	$ 51	$ 0.46	$ 56	$ 0.54
Non-cash stock-based compensation	37	0.34	48	0.46
Total general and administrative expenses	$ 88	$ 0.80	$ 104	$ 1.00

General and administrative expenses for the year ended December 31, 2020 as compared to the year ended December 31, 2019 decreased by $16 million primarily due to a decrease in non-cash stock-based compensation.

Net Interest Expense. The following table shows net interest expense for the years ended December 31, 2020 and 2019:

	Year Ended December 31, 2020	**2019**
	(in millions)	
Interest expense, net	$ 197	$ 172

Net interest expense increased by $25 million for the year ended December 31, 2020 as compared to the year ended December 31, 2019. This increase was primarily due to an increase in borrowings resulting from the issuance of the May 2020 Notes and the Rattler Notes. See Note 11—Debt for further details regarding outstanding borrowings and interest expense.

Derivatives. The following table shows the net gain (loss) on derivative instruments and the net cash received (paid) on settlements of derivative instruments for the years ended December 31, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
	(in millions)	
Gain (loss) on derivative instruments, net	$ (81)	$ (108)
Net cash received (paid) on settlements	$ 250	$ 80

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains; while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Net cash received (paid) on settlements of derivative instruments for the years ended December 31, 2020 and 2019 include cash received on contracts terminated prior to their contractual maturity of $17 million related to commodity contracts and $43 million related to interest rate swap contracts, respectively.

Provision for (Benefit from) Income Taxes. The following table shows the provision for (benefit from) income taxes for the years ended December 31, 2020 and 2019:

	Year Ended December 31,	
	2020	2019
	(in millions)	
Provision for (benefit from) income taxes	$ (1,104)	$ 47

The change in our income tax provision was primarily due to the pre-tax loss for the year ended December 31, 2020 as compared to pre-tax income for the year ended December 31, 2019, and the impact of recording a valuation allowance on Viper's deferred tax assets during the year ended December 31, 2020.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows from operations, proceeds from our public equity offerings, borrowings under our revolving credit facility and proceeds from the issuance of the senior notes. Our primary uses of capital have been for the acquisition, development and exploration of oil and natural gas properties.

As we pursue our business and financial strategy, we regularly consider which capital resources, including cash flow and 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. Continued prolonged volatility in the capital, financial and/or credit markets due to the COVID-19 pandemic, the depressed commodity markets and/or adverse macroeconomic conditions may limit our access to, or increase our cost of, capital or make capital unavailable on terms acceptable to us or at all.

Liquidity and Cash Flow

Our cash flows for the years ended December 31, 2020 and 2019 are presented below:

	Year Ended December 31,	
	2020	2019
	(in millions)	
Net cash provided by (used in) operating activities	$ 2,118	$ 2,739
Net cash provided by (used in) investing activities	(2,101)	(3,888)
Net cash provided by (used in) financing activities	(37)	1,062
Net change in cash	$ (20)	$ (87)

Operating Activities

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" and Item 1A. "Risk Factors" above.

Net cash provided by operating activities decreased to $2.1 billion for the year ended December 31, 2020 as compared to $2.7 billion for the year ended December 31, 2019, primarily due to a decline in our oil and natural gas revenues, which was partially offset by a decrease in lease operating expenses and other operating expenses and an increase in cash received on settlements of our derivative contracts.

Investing Activities

The purchase and development of oil and natural gas properties and related assets, and contributions to our equity method investments accounted for the majority of our $2.1 billion and $3.9 billion in cash outlays for investing activities during the years ended December 31, 2020 and 2019, respectively.

Contributions to equity method investments decreased to $102 million for the year ended December 31, 2020 as compared to $485 million for the year ended December 31, 2019 as construction of both the EPIC Pipeline and Gray Oak Pipeline, which required substantial capital in 2019, was completed during April 2020. As of December 31, 2020, Rattler's anticipated future capital commitments for its equity method investments total $72 million in the aggregate. For additional information regarding our equity method investments, see Note 10—Equity Method Investments included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Capital Expenditure Activities

Our capital expenditures excluding acquisitions and equity method investments (on a cash basis) were as follows for the specified period:

	Year Ended December 31,	
	2020	**2019**
	(in millions)	
Drilling, completions and non-operated additions to oil and natural gas properties(1)(2)	$ 1,611	$ 2,557
Infrastructure additions to oil and natural gas properties	108	120
Additions to midstream assets	140	244
Total	$ 1,859	$ 2,921

(1) During the year ended December 31, 2020, in conjunction with our development program, we drilled 208 gross (195 net) operated horizontal wells, of which 75 gross (70 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 171 gross (159 net) operated horizontal wells to production, of which 78 gross (74 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin.

(2) During the year ended December 31, 2019, in conjunction with our development program, we drilled 330 gross (296 net) operated horizontal wells, of which 159 gross (142 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin, and turned 317 gross (289 net) operated horizontal wells to production, of which 139 gross (126 net) wells were in the Delaware Basin and the remaining wells were in the Midland Basin.

Financing Activities

During the year ended December 31, 2020, the amount used in financing activities was primarily attributable to $348 million of repayments, net of borrowings, on our credit facilities, $239 million in aggregate repayments on the Energen Notes and Viper Notes, $236 million in dividends paid to stockholders, $98 million of share repurchases as part of our stock repurchase program, and $93 million in distributions to non-controlling interest. These cash outlays were partially offset by net proceeds of $997 million from the issuance of the May 2020 Notes and the Rattler Notes during 2020.

During the year ended December 31, 2019, the amount provided by financing activities was primarily attributable to $341 million in net proceeds from Viper's public offering completed on March 1, 2019, $720 million in net proceeds from the Rattler Offering, $39 million in proceeds from joint ventures and $2.2 billion in proceeds from the December 2019 Notes, net of repayments, partially offset by $1.4 billion of repayments, net of borrowings, under our credit facility, $44 million of premium on debt extinguishment, $122 million of distributions to our non-controlling interest, $13 million of share repurchases for tax withholdings, $593 million of share repurchases as part of our stock repurchase program and $112 million of dividends to stockholders.

Indebtedness

Second Amended and Restated Credit Facility

At December 31, 2020, the maximum credit amount available under our credit agreement was $2.0 billion and the maturity date is November 1, 2022. As of December 31, 2020, we had approximately $23 million of outstanding borrowings under our revolving credit facility, which we believe provides ample availability for future borrowings, including funding for the cash portion of the Guidon acquisition in the first quarter of 2021. As of December 31, 2020, there was an aggregate of $3 million in letters of credit outstanding under our credit agreement, which reduce available borrowings on a dollar for dollar basis. The weighted average interest rate on the credit agreement was 2.02% for the year ended December 31, 2020.

The credit agreement contains a financial covenant that requires us to maintain a total net debt to capitalization ratio (as defined in the credit agreement) of no more than 65%. Our non-guarantor restricted subsidiaries may incur debt for borrowed money in an aggregate principal amount up to 15% of consolidated net tangible assets (as defined in the credit agreement) and we and our restricted subsidiaries may incur liens if the aggregate amount of debt secured by such liens does not exceed 15% of consolidated net tangible assets.

At December 31, 2020, we were in compliance with all financial maintenance covenants under the credit agreement, as then in effect. 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.

The May 2020 Notes and Tender Offer for Energen's 4.625% Senior Notes and Repurchase of Energen's 7.35% Medium-term Notes

On May 26, 2020, we completed a registered offering of $500 million in aggregate principal amount of our 4.750% Senior Notes due 2025. Interest on the May 2020 Notes accrues from May 26, 2020, and is payable in cash semi-annually on May 31 and November 30 of each year, beginning November 30, 2020. The May 2020 Notes mature on May 31, 2025. We received net proceeds of approximately $496 million from the offering.

We used the net proceeds, among other things, to make an equity contribution to Energen to purchase $209 million in aggregate principal amount of Energen's 4.625% senior notes pursuant to a tender offer. As of December 31, 2020, $191 million in aggregate principal amount of Energen's 4.625% senior notes remained outstanding.

During the third quarter of 2020, we repurchased all $10 million in principal amount of Energen's outstanding 7.350% medium-term notes due on July 28, 2027 at a price of 120% of the aggregate principal amount.

For additional information, see Note 11—Debt included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Energen Notes

On November 29, 2018, 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. As of December 31, 2020, the aggregate principal amount of the Energen Notes had been reduced to $311 million consisting of: (a) $191 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, and (c) $20 million of 7.32% notes due on July 28, 2022.

For additional information regarding the Energen Notes, See Note 11—Debt included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Viper's Credit Agreement

The Viper credit agreement provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on Viper LLC's oil and natural gas reserves and other factors (the "borrowing base") of $580 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, and was reaffirmed at $580 million by the lenders during the regularly scheduled (semi-annual) fall 2020 redetermination in November 2020. As of December 31, 2020, Viper LLC had $84 million of outstanding borrowings and $496 million available for future borrowings under the Viper credit agreement. During the year ended December 31, 2020, the weighted average interest rate on Viper's revolving credit facility was 2.20%.

As of December 31, 2020, Viper LLC was in compliance with all financial maintenance covenants under the Viper credit agreement, as then in effect.

Viper's Notes

On October 16, 2019, Viper completed an offering in which it issued its 5.375% Senior Notes due 2027 in aggregate principal amount of $500 million. Viper received net proceeds of approximately $490 million from the notes offering and loaned the gross proceeds to Viper LLC to pay down borrowings under the Viper credit agreement. Interest on the Viper notes accrues at a rate of 5.375% per annum, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2020. The Viper notes will mature on November 1, 2027.

During the year ended December 31, 2020, Viper repurchased $20 million of outstanding principal of the Viper notes at a cash price ranging from 97.5% to 98.5% of the aggregate principal amount, which resulted in an immaterial gain on extinguishment of debt, and $480 million in aggregate principal amount remained outstanding at December 31, 2020.

See additional discussion in Note 11—Debt included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Rattler's Credit Agreement

In connection with the Rattler Offering, Rattler, as parent, and Rattler LLC, as borrower, entered into a credit agreement, dated May 28, 2019, with Wells Fargo Bank, as administrative agent, and a syndicate of banks, as lenders party thereto, which we refer to as the Rattler credit agreement.

The Rattler credit agreement provides for a revolving credit facility in the maximum credit amount of $600 million and has a maturity date of May 28, 2024. As of December 31, 2020, Rattler LLC had $79 million of outstanding borrowings and $521 million available for future borrowings under the Rattler credit agreement. During the year ended December 31, 2020, the weighted average interest rate on the Rattler LLC revolving credit facility was 2.10%.

As of December 31, 2020, Rattler LLC was in compliance with all financial maintenance covenants under the Rattler credit agreement.

Rattler's Notes

On July 14, 2020, Rattler completed an offering of $500 million in aggregate principal amount of its 5.625% Senior Notes due 2025, or the Rattler Notes Offering. Interest on the Rattler notes is payable on January 15 and July 15 of each year, beginning on January 15, 2021. The Rattler notes mature on July 15, 2025. Rattler received net proceeds of approximately $490 million from the Rattler Notes Offering. Rattler loaned the gross proceeds to Rattler LLC under the terms of a subordinated promissory note, dated as of July 14, 2020. The promissory note requires Rattler LLC to repay the intercompany loan to Rattler on the same terms and in the same amounts as the Rattler notes and has the same maturity date, interest rate, change of control repurchase and redemption provisions. Rattler LLC used the proceeds from the Rattler Notes Offering to repay a portion of the outstanding borrowings under the Rattler credit agreement.

For additional information regarding our indebtedness, see Note 11—Debt included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2021 capital budget for drilling, midstream and infrastructure of $1.4 billion to $1.6 billion, representing a decrease of 50% from our 2020 capital budget. We estimate that, of these expenditures, approximately:

- $1.2 billion to $1.4 billion will be spent on drilling and completing 215 to 235 gross (197 to 215 net) horizontal wells across our operated leasehold acreage in the Northern Midland and Southern Delaware Basins, with an average lateral length of approximately 10,100 feet;

- $60 million to $80 million will be spent on midstream infrastructure, excluding joint venture investments; and
- $70 million to $90 million will be spent on infrastructure and other expenditures, excluding the cost of any leasehold and mineral interest acquisitions.

We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted.

During the year ended December 31, 2020, we spent $1.6 billion on drilling and completion, $140 million on midstream, $108 million on infrastructure and $58 million on non-operated properties, for total capital expenditures of $1.9 billion.

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 repurchased approximately $98 million of our common stock under this program during the year ended December 31, 2020, prior to the program's expiration.

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 eight drilling rigs and nine 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 2021, we believe our cash flows from operations, cash on hand and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2021. 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 2021 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 the results of our 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.

Guarantor Financial Information

As of December 31, 2020, Diamondback O&G LLC is the sole guarantor under the December 2019 Notes Indenture governing the December 2019 Notes, the May 2020 Notes and the 2025 Indenture governing the 2025 Senior Notes.

Guarantees are "full and unconditional," as that term is used in Regulation S-X, Rule 3-10(b)(3), except that such guarantees will be released or terminated in certain circumstances set forth in the December 2019 Notes Indenture and the 2025 Indenture, such as, with certain exceptions, (1) in the event Diamondback O&G LLC (or all or substantially all of its assets) is sold or disposed of, (2) in the event Diamondback O&G LLC ceases to be a guarantor of or otherwise be an obligor under certain other indebtedness, and (3) in connection with any covenant defeasance, legal defeasance or satisfaction and discharge of the relevant indenture.

Diamondback O&G LLC's guarantees of the December 2019 Notes, the May 2020 Notes and the 2025 Senior Notes are senior unsecured obligations and rank senior in right of payment to any of its future subordinated indebtedness, equal in right of payment with all of its existing and future senior indebtedness, including its obligations under its revolving credit facility, and effectively subordinated to any of its existing and future secured indebtedness, to the extent of the value of the collateral securing such indebtedness.

The rights of holders of the Senior Notes against Diamondback O&G LLC may be limited under the U.S. Bankruptcy Code or state fraudulent transfer or conveyance law. Each guarantee contains a provision intended to limit Diamondback O&G LLC's liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent conveyance. However, there can be no assurance as to what standard a court will apply in making a determination of the maximum liability of Diamondback O&G LLC. Moreover, this provision may not be effective to protect the guarantee from being voided under fraudulent conveyance laws. There is a possibility that the entire guarantee may be set aside, in which case the entire liability may be extinguished.

The following tables present summarized financial information for Diamondback Energy, Inc., as the parent, and Diamondback O&G LLC, as the guarantor subsidiary, on a combined basis after elimination of (i) intercompany transactions and balances between the parent and the guarantor subsidiary and (ii) equity in earnings from and investments in any subsidiary that is a non-guarantor. The information is presented in accordance with the requirements of Rule 13-01 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiary operated as an independent entity.

Summarized Balance Sheets:	**December 31, 2020** (in millions)	
Assets:		
Current assets	$	308
Property and equipment, net	$	6,934
Other noncurrent assets	$	6
Liabilities:		
Current liabilities	$	355
Intercompany accounts payable, non-guarantor subsidiary	$	335
Long-term debt	$	4,293
Other noncurrent liabilities	$	886

Summarized Statement of Operations:	**Year Ended December 31, 2020** (in millions)	
Revenues	$	1,618
Income (loss) from operations	$	(3,466)
Net income (loss)	$	(2,344)

Contractual Obligations

The following table summarizes our contractual obligations and commitments as of December 31, 2020:

	Payments Due by Period				
	2021	2022-2023	2024-2025	Thereafter	Total
	(in millions)				
Secured revolving credit facility(1)	$ —	$ 23	$ —	$ —	$ 23
Senior notes	191	20	2,300	2,100	4,611
Interest expense related to the senior notes(2)	181	342	279	212	1,014
DrillCo Agreement	—	—	—	79	79
Viper's secured revolving credit facility(1)	—	84	—	—	84
Viper's senior notes	—	—	—	480	480
Interest expense related to Viper's senior notes	26	52	52	52	182
Rattler's secured revolving credit facility(1)	—	—	79	—	79
Rattler's senior notes	—	—	500	—	500
Interest expense related to Rattler's senior notes	28	56	55	—	139
Asset retirement obligations(3)	1	—	—	108	109
Drilling commitments(4)	29	—	—	—	29
Sand supply agreements	18	36	36	5	95
Transportation commitments	60	111	95	133	399
Equity method investment capital contributions(5)	57	15	—	—	72
Produced water disposal commitments	5	9	9	33	56
Operating lease obligations(6)	6	3	—	—	9
	$ 602	$ 751	$ 3,405	$ 3,202	$ 7,960

(1) Includes the outstanding principal amount under the revolving credit facilities, the table does not include commitment fees, interest expense or other fees payable under this floating rate facility as we cannot predict the timing of future borrowings and repayments or interest rates to be charged.
(2) Interest represents the scheduled cash payments on the senior notes and Energen Notes.
(3) Amounts represent our estimates of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 9—Asset Retirement Obligations in the notes to the consolidated financial statements included elsewhere in this Annual Report.
(4) Drilling commitments represent future minimum expenditure commitments for drilling rig services under contracts to which the Company was a party on December 31, 2020.
(5) Timing of when capital commitments will be requested can vary.
(6) Operating lease obligations represent future commitments for building, equipment and vehicle leases.

The table above does not include estimated deficiency fees related to certain volume commitments as they are based off future volume deliveries and differences from market pricing which we cannot predict.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States.

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated by our 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 we report for assets and liabilities and our disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Critical accounting policies cover accounting estimates that are inherently uncertain because the future resolution of such matters is unknown and actual results could differ from those estimates.

Any effects on our 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 (i) the method of accounting for our oil and natural gas properties, (ii) estimates of proved oil and gas reserves and related present value estimates of future net cash flows therefrom, (iii) impairments of the carrying value of oil and natural gas properties, (iv) fair value estimates of commodity derivatives and (v) estimates of income taxes.

Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments.

Method of accounting for oil and natural gas properties

We account for our oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. We also capitalize direct operating costs for services performed with internally owned drilling and well servicing equipment. 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. All internal costs unrelated to drilling activities are expensed as incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Income from services provided to working interest owners of properties in which we also own an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties.

Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. If our production remains at approximately the same level from year to year, depletion expense may be significantly different if our estimate of remaining reserves or future development costs changes significantly.

Costs associated with unevaluated properties are excluded from the full cost pool until we have made a determination as to the existence of proved reserves. We assess all items classified as unevaluated property on an annual basis for possible impairment. We assess properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. The SEC has defined proved reserves as the estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. The process of estimating oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. If such changes are material, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Impairment

Under the full cost method of accounting, we are required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions 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 write-down is required. Impairments of our evaluated oil and natural gas properties are not reversible.

Derivatives

From time to time, we have used energy derivatives for the purpose of mitigating the risk resulting from fluctuations in the market price of crude oil and natural gas. We exercise significant judgment in determining the types of instruments to be used, the level of production volumes to include in our commodity derivative contracts, the prices at which we enter into commodity derivative contracts and the counterparties' creditworthiness.

We have not designated our derivative instruments as hedges for accounting purposes and, as a result, mark our derivative instruments to fair value and recognize the cash and non-cash change in fair value on derivative instruments for each period in the consolidated statements of operations. We are also required to recognize our derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation, and 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, including any deferred premiums, that are with the same counterparty and are subject to contractual terms which provide for net settlement. Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur.

Income Taxes

The amount of income taxes we record requires interpretations of complex rules and regulations of federal, state, and provincial tax jurisdictions. We use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The accruals for deferred tax assets and liabilities are often based on assumptions that are subject to a significant amount of judgment by management. These assumptions and judgments are reviewed and adjusted as facts and circumstances change. Material changes to our income tax accruals may occur in the future based on the progress of ongoing audits, changes in legislation or resolution of pending matters.

See Note 2—Summary of Significant Accounting Policies of the notes to the consolidated financial statements included elsewhere in this Annual Report for a full discussion of our significant accounting policies.

Recent Accounting Pronouncements

For information regarding recent accounting pronouncements, See Note 2—Summary of Significant Accounting Policies included in notes to the consolidated financial statements included elsewhere in this Annual Report.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of December 31, 2020. Please read Note 17—Commitments and Contingencies included in notes to the consolidated financial statements included elsewhere in this Form 10-K for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure in our exploration and production business 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 derivatives, including swaps, basis swaps, swaptions, roll hedges and costless collars, to reduce price volatility associated with certain of our oil and natural gas sales.

At December 31, 2020, we had a net liability derivative position of $255 million related to our commodity price risk derivatives. Utilizing actual derivative contractual volumes under our commodity price derivatives as of December 31, 2020, a 10% increase in forward curves associated with the underlying commodity would have increased the net liability position to $284 million, an increase of $29 million, while a 10% decrease in forward curves associated with the underlying commodity would have decreased the net liability derivative position to $226 million, a decrease of $29 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.

In our midstream operations business, we have indirect exposure to commodity price risk in that persistent low commodity prices may cause us or Rattler's other customers to delay drilling or shut in production, which would reduce the volumes available for gathering and processing by our infrastructure assets. If we or Rattler's other customers delay drilling or temporarily shut in production due to persistently low commodity prices or for any other reason, our revenue in the midstream operations segment could decrease, as Rattler's commercial agreements do not contain minimum volume commitments.

For additional information on our open commodity derivative instruments at December 31, 2020, see Note 15—Derivatives.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are due to the concentration of receivables from the sale of our oil and natural gas production (approximately $281 million at December 31, 2020), and to a lesser extent, receivables resulting from joint interest receivables (approximately $56 million at December 31, 2020).

We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us due to their liquidity issues, bankruptcy, insolvency or liquidation may adversely affect our financial results. For the year ended December 31, 2020, four purchasers each accounted for more than 10% of our revenue. For each of the years ended December 31, 2019 and 2018, three purchasers each accounted for more than 10% of our revenue. No other customer accounted for more than 10% of our revenue during these periods. Our allowances for credit losses were insignificant at December 31, 2020.

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.

The ongoing COVID-19 pandemic, depressed commodity pricing environment and adverse macroeconomic conditions may enhance our customer credit risk.

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 0.125% to 1.0% per annum in the case of the alternative base rate and from 1.125% to 2.0% per annum in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. Historically, we have used interest rate swaps and treasury locks to reduce our exposure to variable rate interest payments associated with our revolving credit facility.

The following table summarizes the Company's interest rate swaps as of December 31, 2020:

Type	Effective Date	Contractual Termination Date	Notional Amount (in millions)	Interest Rate
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.692 %
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.8361 %
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.852 %
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.722 %

For additional information on our variable interest rate debt at December 31, 2020, see Note 11—Debt. See Note 18—Subsequent Events for discussion of derivative transactions which occurred subsequent to December 31, 2020.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this item appears beginning on page F-1 of this report.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. 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 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 December 31, 2020, 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 December 31, 2020, 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 December 31, 2020 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed under the supervision of the Company's Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting based on the framework in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in the 2013 Internal Control-Integrated Framework, management did not identify any material weaknesses in the Company's internal control over financial reporting and determined that the Company maintained effective internal control over financial reporting as of December 31, 2020.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Grant Thornton LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued their report on the effectiveness of the Company's internal control over financial reporting at December 31, 2020. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting at December 31, 2020, is included in this Item under the heading "Report of Independent Registered Public Accounting Firm."

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Diamondback Energy, Inc.

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2020, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of and for the year ended December 31, 2020, and our report dated February 25, 2021 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 25, 2021

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information as to Item 10 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

We have adopted a Code of Business Conduct and Ethics that applies to our Chief Executive Officer, Chief Financial Officer, principal accounting officer and controller and persons performing similar functions. Any amendments to or waivers from the code of business conduct and ethics will be disclosed on our website. The Company also has made the Code of Business Conduct and Ethics available on our website under the "Corporate Governance" section at http://ir.diamondbackenergy.com. We intend to satisfy the disclosure requirements under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the Code of Business Conduct and Ethics by posting such information on our website at the address specified above.

ITEM 11. EXECUTIVE COMPENSATION

Information as to Item 11 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information as to Item 12 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information as to Item 13 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information as to Item 14 will be set forth in our definitive proxy statement, which is to be filed pursuant to Regulation 14A with the SEC within 120 days after the close of the year ended December 31, 2020.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents included in this report:

1. Financial Statements

2. Financial Statement Schedules

Financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the Company's consolidated financial statements and related notes.

3. Exhibits

Exhibit Number	Description
2.1#	Agreement and Plan of Merger, dated as of December 20, 2020, by and among Diamondback Energy, Inc., Bohemia Merger Sub, Inc. and QEP Resources, Inc. (incorporated by reference to Exhibit 2.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 21, 2020).
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	Second 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 November 19, 2019).
4.1	Description of the Company's Securities (incorporated by reference to Exhibit 4.1 to the Form 10-K, File No. 000-35700, filed by the Company with the SEC on February 27, 2020).
4.2	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).
4.3	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).
4.4	First Supplemental Indenture for the 5.375% Senior Notes due 2025, 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).
4.5	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).
4.6	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).
4.7	Indenture, dated as of December 5, 2019, between Diamondback Energy, Inc. 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 December 5, 2019).

3. Exhibits

Exhibit Number	Description
4.8	First Supplemental Indenture, dated as of December 5, 2019, among Diamondback Energy, Inc., Diamondback O&G LLC and Wells Fargo Bank, National Association, as trustee (including the form of 2024 Notes, 2026 Notes and 2029 Notes) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 5, 2019).
4.9	Second Supplemental Indenture, dated as of May 26, 2020, among Diamondback Energy, Inc., Diamondback O&G LLC and Wells Fargo Bank, National Association, as trustee (including the form of Notes) (incorporated by reference to Exhibit 4.2 to the Form 8-K, File No 001-35700, filed by the Company with the SEC on May 26, 2020).
4.10	Indenture, dated as of October 16, 2019, among Viper Energy Partners LP, as issuer, Viper Energy Partners LLC, as guarantor, and Wells Fargo Bank, National Association, as trustee (including the form of Viper Energy Partners LP's 5.375% Senior Notes due 2027) (incorporated by reference to Exhibit 4.1 of Viper Energy Partners LP's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
4.11	Consent Letter, dated August 28, 2019, between Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc. as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File 001-35700) filed on September 4, 2019).
4.12	Subordinated Promissory Note, dated as of October 16, 2019, by Viper Energy Partners LLC in favor of Viper Energy Partners LP (incorporated by reference to Exhibit 10.2 of Viper Energy Partners LP's Current Report on Form 8-K (File 001-36505) filed on October 17, 2019).
4.13	Indenture, dated as of July 14, 2020, among Rattler Midstream LP, as issuer, Rattler Midstream Operating LLC, Tall City Towers LLC, Rattler Ajax Processing LLC, and Rattler OMOG LLC, as guarantors, and Wells Fargo Bank, National Association, as trustee (including the form of Rattler Midstream LP's 5.625% Senior Notes due 2025) (incorporated by reference to Exhibit 4.1 to the Form 8-K, File No. 001-38919, filed by Rattler Midstream LP with the SEC on July 14, 2020).
4.14	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	Diamondback Energy, Inc. 2019 Amended and Restated Equity Incentive Plan (incorporated by reference to Appendix A to Schedule DEFA 14A filed by the Company with the SEC on April 26, 2020).
10.2+	2020 Form of Time Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 of the Company's Annual Report on Form 10-K (File 001-35700) filed on February 27, 2020).
10.3+	2020 Form of Performance Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.3 of the Company's Annual Report on Form 10-K (File 001-35700) filed on February 27, 2020).
10.4+*	2021 Form of Time Vesting Restricted Stock Unit Award Agreement.
10.5+*	2021 Form of Performance Vesting Restricted Stock Unit Agreement.
10.6+	Form of Time-Vesting Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on March 5, 2014).
10.7+	Form of Performance-Based Restricted Stock Unit Award Agreement (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the SEC on March 5, 2014).
10.8+	Form of Director and Officer Indemnification Agreement (incorporated by reference to Exhibit 10.15 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).
10.9+	Diamondback Energy, Inc. Senior Management Severance Plan (including forms of participation agreements attached thereto as Schedules C-1 and C-2) (incorporated by reference to Exhibit 10.5 of the Company's Annual Report on Form 10-K (File 001-35700) filed on February 27, 2020).
10.10+	2014 Executive Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on April 2, 2014).
10.11+*	Executive Annual Incentive Compensation Plan adopted in February 2021.
10.12	Second Amended and Restated Credit Agreement, dated as of November 1, 2013, among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 5, 2013).

Table of Contents

3. Exhibits

Exhibit Number	Description
10.13	First Amendment, dated June 9, 2014, to the Second Amended and Restated Credit Agreement, originally dated November 1, 2013, by and among the Company, as parent guarantor, Diamondback O&G LLC, as borrower, each of the guarantors party thereto, each of the lenders party thereto and Wells Fargo Bank, National Association, as administrative agent (incorporated by reference to Exhibit 10.4 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on August 7, 2014).
10.14	Second Amendment to the Second Amended and Restated Credit Agreement, dated as of November 13, 2014, among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, the guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 18, 2014).
10.15	Third Amendment, dated as of June 21, 2016, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on June 27, 2016).
10.16	Fourth Amendment, dated as of December 15, 2016, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 20, 2016).
10.17	Fifth Amendment, dated as of November 28, 2017, to the Second Amended and Restated Credit Agreement, dated as of November 1, 2013, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 4, 2017).
10.18	Eighth Amendment to the Second Amended and Restated Credit Agreement, dated as of October 26, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on November 1, 2018).
10.19	Ninth Amendment to Second Amended and Restated Credit Agreement and Fourth Amendment to Amended and Restated Guaranty and Collateral Agreement, dated as of November 29, 2018, by and among Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc., as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on December 6, 2018).
10.20	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).
10.21	Eleventh Amendment to Second Amended and Restated Credit Agreement, dated as of June 28, 2019, between Diamondback Energy, Inc., as parent guarantor, Diamondback O&G LLC, as borrower, certain other subsidiaries of Diamondback Energy, Inc. as guarantors, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Form 8-K, File No. 001-35700, filed by the Company with the SEC on July 3, 2019).
10.22	Amended and Restated Credit Agreement, dated as of July 20, 2018, by and among, Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Current Report on Form 8-K (File 001-36505) filed by Viper Energy Partners LP on July 26, 2018).
10.23	Second Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of September 24, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of Viper Energy Partners LP's Form 8-K (File 001-36505) filed on September 30, 2019).

3. Exhibits

Exhibit Number	Description
10.24	Third Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of October 8, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lender party thereto (incorporated by reference to Exhibit 10.1 of Viper Energy Partners LP's Form 8-K (File 001-36505) filed on October 10, 2019).
10.25	Fourth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of November 29, 2019, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File No. 001-36505) filed on December 5, 2019).
10.26	Fifth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of May 11, 2020, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on May 15, 2020).
10.27	Sixth Amendment to Amended and Restated Senior Secured Revolving Credit Agreement, dated as of November 6, 2020, among Viper Energy Partners LLC, as borrower, Viper Energy Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Partnership's Current Report on Form 8-K (File 001-36505) filed on November 12, 2020).
10.28	Credit Agreement, dated May 28, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto (incorporated by reference to Exhibit 10.2 to Rattler Midstream LP's Form 8-K, File No. 001-38919, filed by Rattler Midstream LP with the SEC on May 29, 2019).
10.29	First Amendment to the Credit Agreement, dated as of October 23, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto (incorporated by reference to Exhibit 10.1 of Rattler Midstream LP's Form 8-K (File 001-38919) filed on October 28, 2019).
10.30	Second Amendment, dated as of November 2, 2020, to the Credit Agreement, dated May 28, 2019, as amended on October 23, 2019, by and among Rattler Midstream Operating LLC, as borrower, Rattler Midstream LP, as parent, Wells Fargo Bank, National Association, as the administrative agent, and certain lenders from time to time party thereto. (incorporated by reference to Exhibit 10.3 of the Partnership's Quarterly Report on Form 10-Q (File 001-38919) filed on November 5, 2020).
10.31+	Energen Corporation Stock Incentive Plan (as amended effective November 7, 2017) (incorporated by reference to Exhibit 10(b) to Energen's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2017).
10.32+	Amendment to the Energen Corporation Stock Incentive Plan, dated November 27, 2018 (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-8, File No. 333-228637, filed by the Company with the SEC on November 30, 2018).
10.33+	Form of Stock Option Agreement under the Energen Corporation Stock Incentive Plan (incorporated by reference to Exhibit 10(r) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012).
10.34+	Form of Restricted Stock Agreement under the Energen Corporation Stock Incentive Plan (incorporated by reference to Exhibit 10(s) to Energen's Annual Report on Form 10-K for the year ended December 31, 2012).
10.35+	Form of Restricted Stock Unit Agreement under the Energen Corporation Stock Incentive Plan (incorporated by reference to Exhibit 10.2 to Energen's Current Report on Form 8-K filed December 12, 2013).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of Ryder Scott Company, L.P. with respect to the Diamondback Energy, Inc. reserve report included as Exhibit 99.1.
23.3*	Consent of Ryder Scott Company, L.P. with respect to the Viper Energy Partners LP reserve report included as Exhibit 99.2.
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.

3. Exhibits

Exhibit Number	Description
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.
99.1*	Report of Ryder Scott Company, L.P., dated January 7, 2021, with respect to an estimate of the proved reserves, future production and income attributable to certain leasehold interests of Diamondback Energy, Inc. as of December 31, 2020.
99.2*	Report of Ryder Scott Company, L.P., dated January 7, 2021, with respect to an estimate of the proved reserves, future production and income attributable to certain royalty interests of Viper Energy Partners LP, a subsidiary of Diamondback Energy, Inc., as of December 31, 2020.
101	The following financial information from the Company’s Annual Report on Form 10-K for the year ended December 31, 2020, formatted in Inline XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statement of Changes in Stockholders’ Equity, (iv) Consolidated Statements of Cash Flows and (v) Notes to Consolidated Financial Statements.
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101).

* 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.

\+ Management contract, compensatory plan or arrangement.

\# The schedules (or similar attachments) referenced in this agreement have been omitted in accordance with Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule (or similar attachment) will be furnished supplementally to the Securities and Exchange Commission upon request.

ITEM 16. FORM 10-K SUMMARY

None.

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: February 25, 2021

/s/ Travis D. Stice
Travis D. Stice
Chief Executive Officer
(Principal Executive Officer)

Pursuant to the requirements of the Securities and Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Steven E. West Steven E. West	Chairman of the Board and Director	February 25, 2021
/s/ Travis D. Stice Travis D. Stice	Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2021
/s/ Vincent K. Brooks Vincent K. Brooks	Director	February 25, 2021
/s/ Michael P. Cross Michael P. Cross	Director	February 25, 2021
/s/ David L. Houston David L. Houston	Director	February 25, 2021
/s/ Stephanie K. Mains Stephanie K. Mains	Director	February 25, 2021
/s/ Mark L. Plaumann Mark L. Plaumann	Director	February 25, 2021
/s/ Melanie M. Trent Melanie M. Trent	Director	February 25, 2021
/s/ Kaes Van't Hof Kaes Van't Hof	Chief Financial Officer and Executive Vice President—Business Development (Principal Financial Officer)	February 25, 2021
/s/ Teresa L. Dick Teresa L. Dick	Chief Accounting Officer, Executive Vice President and Assistant Secretary (Principal Accounting Officer)	February 25, 2021

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Diamondback Energy, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (collectively the "Company") as of December 31, 2020 and 2019, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2020, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in the 2013 *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), and our report dated February 25, 2021 expressed an unqualified opinion.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matter

The critical audit matter communicated below is a matter arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Estimation of proved reserves as it relates to the calculation and recognition of depletion expense and the evaluation of impairment

As described in Note 2 to the financial statements, the Company accounts for its oil and gas properties using the full cost method of accounting which requires management to make estimates of proved reserve volumes and future revenues to record depletion expense and measure its oil and gas properties for potential impairment. To estimate the volume of proved reserves and future revenues, management makes significant estimates and assumptions, including forecasting the production decline rate of producing properties and forecasting the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment measurements. We identified the estimation of proved reserves of oil and gas properties, due to its impact on depletion expense and impairment evaluation, as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that relatively minor changes in certain inputs and assumptions, which require a high degree of subjectivity, necessary to estimate the volume and future revenues of the Company's proved reserves could have a significant impact on the measurement of depletion expense or impairment expense. In turn, auditing those inputs and assumptions required subjective and complex auditor judgment.

Our audit procedures related to the estimation of proved reserves included the following, among others.

- We tested the design and operating effectiveness of key controls relating to the preparation of the ceiling test calculation and management's estimation of proved reserves for the purpose of estimating depletion expense and assessing the Company's oil and gas properties for potential impairment. Specifically, these controls related to the use of historical information in the estimation of proved reserves derived from the Company's accounting records and the management review controls on information provided to the reservoir engineering specialists and the management review controls on the final proved reserve report prepared by the Company's specialists.

- We evaluated the level of knowledge, skill, and ability of the Company's reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and read the reserve report prepared by the Company's specialists.

- To the extent key, sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, such as historical pricing differentials, operating costs, estimated capital costs and working and net revenue interests, we tested management's process for determining the assumptions, including examining the underlying support, on a sample basis. Specifically, our audit procedures involved testing management's assumptions as follows:

  – Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;

  – Evaluated the models used to estimate the operating costs at year-end compared to historical operating costs;

  – Compared the models used to determine the future capital expenditures and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells with similar locations;

  – Evaluated the working and net revenue interests used in the reserve report by inspecting a sample of land and division order records;

  – Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining historical conversion rates and support for the Company's or the operator's intent to develop the proved undeveloped properties;

  – Evaluated the estimated ultimate recovery of proved undeveloped properties to the estimated ultimate recovery of comparable proved developed producing properties; and

  – Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year reserve report.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2009.

Oklahoma City, Oklahoma
February 25, 2021

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2020	December 31, 2019
	(In millions, except par value and share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 104	$ 123
Restricted cash	4	5
Accounts receivable:		
Joint interest and other, net	56	186
Oil and natural gas sales, net	281	429
Inventories	33	37
Derivative instruments	1	46
Income tax receivable	100	19
Prepaid expenses and other current assets	23	24
Total current assets	602	869
Property and equipment:		
Oil and natural gas properties, full cost method of accounting ($7,493 million and $9,207 million excluded from amortization at December 31, 2020 and December 31, 2019, respectively)	27,377	25,782
Midstream assets	1,013	931
Other property, equipment and land	138	125
Accumulated depletion, depreciation, amortization and impairment	(12,314)	(5,003)
Property and equipment, net	16,214	21,835
Funds held in escrow	51	—
Equity method investments	533	479
Derivative instruments	—	7
Deferred income taxes, net	73	142
Investment in real estate, net	101	109
Other assets	45	90
Total assets	$ 17,619	$ 23,531
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable - trade	$ 71	$ 179
Accrued capital expenditures	186	475
Current maturities of long-term debt	191	—
Other accrued liabilities	302	304
Revenues and royalties payable	237	278
Derivative instruments	249	27
Total current liabilities	1,236	1,263
Long-term debt	5,624	5,371
Derivative instruments	57	—
Asset retirement obligations	108	94
Deferred income taxes	783	1,886
Other long-term liabilities	7	11
Total liabilities	7,815	8,625
Commitments and contingencies (Note 17)		
Stockholders' equity:		
Common stock, $0.01 par value, 200,000,000 shares authorized, 158,088,182 and 159,002,338 issued and outstanding at December 31, 2020 and December 31, 2019, respectively	2	2
Additional paid-in capital	12,656	12,357
Retained earnings (accumulated deficit)	(3,864)	890
Total Diamondback Energy, Inc. stockholders' equity	8,794	13,249
Non-controlling interest	1,010	1,657
Total equity	9,804	14,906
Total liabilities and equity	$ 17,619	$ 23,531

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Year Ended December 31,		
	2020	2019	2018
	(In millions, except per share amounts, shares in thousands)		
Revenues:			
Oil sales	$ 2,410	$ 3,554	$ 1,879
Natural gas sales	107	66	61
Natural gas liquid sales	239	267	190
Midstream services	50	64	34
Other operating income	7	13	12
Total revenues	2,813	3,964	2,176
Costs and expenses:			
Lease operating expenses	425	490	205
Production and ad valorem taxes	195	248	133
Gathering and transportation	140	88	26
Midstream services expense	105	91	72
Depreciation, depletion and amortization	1,304	1,447	623
Impairment of oil and natural gas properties	6,021	790	—
General and administrative expenses	88	104	65
Asset retirement obligation accretion	7	7	2
Merger and integration expense	—	—	36
Other operating expense	4	4	3
Total costs and expenses	8,289	3,269	1,165
Income (loss) from operations	(5,476)	695	1,011
Other income (expense):			
Interest expense, net	(197)	(172)	(87)
Other income (expense), net	2	4	89
Gain (loss) on derivative instruments, net	(81)	(108)	101
Gain (loss) on revaluation of investment	(9)	5	(1)
Loss on extinguishment of debt	(5)	(56)	—
Income (loss) from equity investments	(10)	(6)	—
Total other income (expense), net	(300)	(333)	102
Income (loss) before income taxes	(5,776)	362	1,113
Provision for (benefit from) income taxes	(1,104)	47	168
Net income (loss)	(4,672)	315	945
Net income (loss) attributable to non-controlling interest	(155)	75	99
Net income (loss) attributable to Diamondback Energy, Inc.	$ (4,517)	$ 240	$ 846
Earnings (loss) per common share:			
Basic	$ (28.59)	$ 1.47	$ 8.09
Diluted	$ (28.59)	$ 1.47	$ 8.06
Weighted average common shares outstanding:			
Basic	157,976	163,493	104,622
Diluted	157,976	163,843	104,929
Dividends declared per share	$ 1.5250	$ 0.9375	$ 0.50

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Non-Controlling Interest	Total
	($ in millions, shares in thousands)					
Balance at December 31, 2017	98,167	$ 1	$ 5,291	$ (38)	$ 327	$ 5,581
Impact of adoption of ASU 2016-01, net of tax	—	—	—	(9)	(7)	(16)
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	303	303
Unit-based compensation	—	—	—	—	3	3
Stock-based compensation	—	—	34	—	—	34
Common shares issued for business combination	63,126	1	7,069	—	—	7,070
Stock options assumed in business combination	—	—	14	—	—	14
Restricted stock units assumed in business combination	—	—	52	—	—	52
Repurchased shares for tax withholding	(140)	—	(14)	—	—	(14)
Distribution to non-controlling interest	—	—	—	—	(98)	(98)
Common shares issued for Ajax	2,584	—	340	—	—	340
Dividend paid	—	—	—	(37)	—	(37)
Exercise of stock options and vesting of restricted stock units	536	—	—	—	—	—
Change in ownership of consolidated subsidiaries, net	—	—	150	—	(160)	(10)
Net income	—	—	—	846	99	945
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
Net proceeds from issuance of common units - Rattler Midstream LP	—	—	—	—	720	720
Unit-based compensation	—	—	—	—	7	7
Common units issued for acquisition	—	—	—	—	124	124
Stock-based compensation	—	—	57	—	—	57
Repurchased shares for tax withholding	(125)	—	(13)	—	—	(13)
Repurchased shares under buyback program	(6,385)	—	(598)	—	—	(598)
Distribution to non-controlling interest	—	—	—	—	(122)	(122)
Dividend paid	—	—	—	(112)	—	(112)
Exercise of stock and unit options and awards of restricted stock	1,239	—	8	—	—	8
Change in ownership of consolidated subsidiaries, net	—	—	(33)	—	45	12
Net income	—	—	—	240	75	315
Balance at December 31, 2019	159,002	2	12,357	890	1,657	14,906
Unit-based compensation	—	—	—	—	10	10
Distribution equivalent rights payments	—	—	—	(1)	(2)	(3)
Stock-based compensation	—	—	43	—	—	43
Repurchased shares for tax withholding	(75)	—	(5)	—	(2)	(7)
Repurchased shares under buyback program	(1,280)	—	(98)	—	—	(98)
Repurchased units under buyback programs	—	—	—	—	(39)	(39)
Distribution to non-controlling interest	—	—	—	—	(93)	(93)
Dividend paid	—	—	—	(236)	—	(236)
Exercise of stock options and vesting of restricted stock units	441	—	1	—	—	1
Change in ownership of consolidated subsidiaries, net	—	—	358	—	(366)	(8)
Net income (loss)	—	—	—	(4,517)	(155)	(4,672)
Balance at December 31, 2020	158,088	$ 2	$ 12,656	$ (3,864)	$ 1,010	$ 9,804

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2020	2019	2018
		(In millions)	
Cash flows from operating activities:			
Net income (loss)	$ (4,672)	$ 315	$ 945
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:			
Provision for (benefit from) deferred income taxes	(1,042)	47	168
Impairment of oil and natural gas properties	6,021	790	—
Depreciation, depletion and amortization	1,304	1,447	623
Loss on early extinguishment of debt	5	56	—
(Gain) loss on derivative instruments, net	81	108	(101)
Cash received (paid) on settlement of derivative instruments	250	80	(121)
Equity-based compensation expense	37	48	27
Other	37	15	18
Changes in operating assets and liabilities:			
Accounts receivable	217	(187)	13
Income tax receivable	(62)	—	—
Prepaid expenses and other	2	29	25
Accounts payable and accrued liabilities	(20)	(129)	(7)
Revenues and royalties payable	(41)	135	12
Other	1	(15)	(37)
Net cash provided by (used in) operating activities	2,118	2,739	1,565
Cash flows from investing activities:			
Drilling, completions and non-operated additions to oil and natural gas properties	(1,611)	(2,557)	(1,359)
Infrastructure additions to oil and natural gas properties	(108)	(120)	(102)
Additions to midstream assets	(140)	(244)	(204)
Acquisitions of leasehold interests	(119)	(443)	(1,371)
Acquisitions of mineral interests	(66)	(333)	(440)
Funds held in escrow	(51)	—	11
Proceeds from sale of assets	63	300	80
Investment in real estate	—	(1)	(111)
Contributions to equity method investments	(102)	(485)	—
Other	33	(5)	(7)
Net cash provided by (used in) investing activities	(2,101)	(3,888)	(3,503)
Cash flows from financing activities:			
Proceeds from borrowings under credit facilities	1,130	2,350	2,652
Repayments under credit facilities	(1,478)	(3,718)	(1,242)
Repayment on Energen's credit facility	—	—	(559)
Proceeds from senior notes	997	3,469	1,062
Repayment of senior notes	(239)	(1,250)	—
Proceeds from joint venture	40	39	—
Premium on extinguishment of debt	(2)	(44)	—
Debt issuance costs	(11)	(18)	(25)
Public offering costs	—	(41)	(3)
Proceeds from public offerings	—	1,106	305
Repurchased shares under buyback program	(98)	(593)	—
Repurchased units under buyback program	(39)	—	—
Dividends to stockholders	(236)	(112)	(37)
Distributions to non-controlling interest	(93)	(122)	(98)
Other	(8)	(4)	(14)
Net cash provided by (used in) financing activities	(37)	1,062	2,041
Net increase (decrease) in cash and cash equivalents	(20)	(87)	103
Cash, cash equivalents and restricted cash at beginning of period	128	215	112
Cash, cash equivalents and restricted cash at end of period	$ 108	$ 128	$ 215

See accompanying notes to consolidated financial statements.

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

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 235	$ 237	$ 114
Supplemental disclosure of non-cash transactions:			
Accrued capital expenditures	$ 213	$ 553	$ 437
Common stock issued for Ajax	$ —	$ —	$ 340
Common stock issued for business combination(1)	$ —	$ —	$ 7,136
Asset retirement obligations acquired	$ 2	$ 4	$ 111

(1) Includes $7 billion of common stock issued for business combination, $14 million for stock options assumed and $52 million for restricted stock units assumed.

See accompanying notes to consolidated financial statements.

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc. ("Diamondback" or the "Company") 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.

The wholly-owned subsidiaries of Diamondback, as of December 31, 2020, 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 ("Viper's General Partner"), Rattler Midstream GP LLC, a Delaware limited liability company ("Rattler's General Partner"), and Energen Corporation, an Alabama corporation ("Energen"). The consolidated subsidiaries include these wholly owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership ("Viper"), Viper's subsidiary Viper Energy Partners LLC, a Delaware limited liability company ("Viper LLC"), Rattler Midstream LP (formerly known as Rattler Midstream Partners LP), a Delaware limited partnership ("Rattler"), Rattler Midstream Operating LLC (formerly known as Rattler Midstream LLC), a Delaware limited liability company ("Rattler LLC"), Rattler LLC's wholly owned subsidiaries Tall City Towers LLC, a Delaware limited liability company ("Tall City"), Rattler Ajax Processing LLC, a Delaware limited liability company, Rattler OMOG LLC, a Delaware limited liability company, Energen's wholly owned subsidiaries Energen Resources Corporation, an Alabama corporation ("Energen Resources"), EGN Services, Inc., an Alabama corporation and Bohemia Merger Sub Inc., a Delaware corporation.

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.

Viper and Rattler are consolidated in the financial statements of the Company. As of December 31, 2020, the Company owned approximately 58% of Viper's total units outstanding. The Company's wholly owned subsidiary, Viper Energy Partners GP LLC, is the general partner of Viper. As of December 31, 2020, the Company owned approximately 72% of Rattler's total units outstanding. The Company's wholly owned subsidiary, Rattler Midstream GP LLC, is the general partner of Rattler. The results of operations attributable to the non-controlling interest in Viper and Rattler are presented within equity and net income and are shown separately from the Company's equity and net income attributable to the Company.

The Company reports its operations in two operating segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas and (ii) the midstream operations segment, which includes midstream services and real estate operations.

Reclassifications

Certain prior period amounts have been reclassified to conform to the current period financial statement presentation. These reclassifications had an immaterial effect on the previously reported total assets, total liabilities, stockholders' equity, results of operations or cash flows.

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.

Making accurate estimates and assumptions is particularly difficult as the oil and natural gas industry experiences challenges resulting from negative pricing pressure from the effects of COVID-19 and actions by OPEC members and other exporting nations on the supply and demand in global oil and natural gas markets. Companies in the oil and natural gas industry have changed near term business plans in response to changing market conditions. The aforementioned circumstances generally increase the uncertainty in the Company's accounting estimates, particularly those involving financial forecasts.

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 derivative instruments and estimates of income taxes.

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a maturity of three months or less and money market funds to be cash equivalents. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments for production are received within three months after the production date.

The Company adopted Accounting Standards Update ("ASU") 2016-13 and the subsequent applicable modifications to the rule on January 1, 2020. Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for expected losses as estimated by the Company when collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable from joint interest owners or purchasers outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance for each type of receivable by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for expected losses. At December 31, 2020 and 2019, the Company recorded immaterial allowances for credit losses related to joint interest receivables and credit losses related to sales of oil and natural gas production.

Derivative Instruments

The Company is required to recognize its derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. 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 change in fair value on derivative instruments for each period in the consolidated statements of operations. For additional information regarding the Company's derivative instruments, see Note 15—Derivatives.

Oil and Natural Gas Properties

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. 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. Any income from services provided by subsidiaries to working interest owners of properties in which the Company also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties proportionate to the Company's investment in the subsidiary. Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $11.30, $13.54 and $12.62 for the years ended December 31, 2020, 2019 and 2018, respectively. Depletion expense for oil and natural gas properties was $1.2 billion, $1.4 billion and $595 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Under this method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and natural gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing 12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions, 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 write-down is required. For additional information regarding the Company's impairments on proved oil and natural gas properties, see Note 8—Property and Equipment.

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 Company assesses all items classified as unevaluated property on at least an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

Real Estate Assets

Real estate assets are stated at cost, less accumulated depreciation and amortization. The Company considers the period of future benefit of each respective asset to determine the appropriate useful life and depreciation and amortization is calculated using the straight-line method over the assigned useful life.

Upon acquisition of real estate properties, the purchase price is allocated to tangible assets, consisting of land and building, and to identified intangible assets and liabilities, which may include the value of above market and below market leases and the value of in-place leases. The allocation of the purchase price is based upon the fair value of each component of the property. Although independent appraisals may be used to assist in the determination of fair value, in many cases these values will be based upon management's assessment of each property, the selling prices of comparable properties and the discounted value of cash flows from the asset. For additional information regarding the Company's real estate assets, see Note 7—Real Estate Assets.

Other Property, Equipment and Land

Other property, equipment and land is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or disposition of assets, the cost and related accumulated depreciation are removed from the consolidated balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight-line method over their estimated useful lives, which range from three to 15 years.

Asset Retirement Obligations

The Company measures the future cost to retire its tangible long-lived assets and recognizes such cost as a liability for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset.

Asset retirement obligations represent the future abandonment costs of tangible assets, namely wells. The fair value of a liability for an asset’s retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made, and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount or if there is a change in the estimated liability, the difference is recorded in oil and natural gas properties.

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. For additional information regarding the Company’s asset retirement obligations, see Note 9—Asset Retirement Obligations.

Impairment of Long-Lived Assets

Other property and equipment used in operations and midstream assets are reviewed whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss is recognized only if the carrying amount of a long-lived asset is not recoverable from its estimated future undiscounted cash flows. An impairment loss is the difference between the carrying amount and fair value of the asset. The Company had no significant impairment losses for the years ended December 31, 2020, 2019 and 2018.

Capitalized Interest

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these unevaluated properties to their intended use. Capitalized interest cannot exceed gross interest expense. See Note 11—Debt for further details.

Inventories

Inventories are stated at the lower of cost or market and consist of tubular goods and equipment at December 31, 2020 and 2019. The Company’s tubular goods and equipment are primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units.

Debt Issuance Costs

Long-term debt includes capitalized costs related to the senior notes, net of accumulated amortization. The costs associated with the senior notes are netted against the senior notes balances and are amortized over the term of the senior notes using the effective interest method. See Note 11—Debt for further details. The costs associated with the Company’s credit facilities are included in other assets on the consolidated balance sheet and are amortized over the term of the facility.

Other Accrued Liabilities

Other accrued liabilities consist of the following:

	December 31, 2020	December 31, 2019
	(In millions)	
Lease operating expenses payable	$ 115	$ 119
Ad valorem taxes payable	57	68
Interest payable	37	27
Derivative liability payable	30	3
Midstream operating expenses payable	18	22
Liability for drilling costs prepaid by joint interest partners	5	12
Other	40	53
Total other accrued liabilities	$ 302	$ 304

Revenue and Royalties Payable

For certain oil and natural gas properties, where the Company serves as operator, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds that the Company has not yet distributed to other revenue and royalty owners are reflected as revenue and royalties payable in the accompanying consolidated balance sheets. The Company recognizes revenue for only its net revenue interest in oil and natural gas properties.

Non-controlling Interests

Non-controlling interests in the accompanying consolidated financial statements represent minority interest ownership in Viper and Rattler and are presented as a component of equity. When the Company's relative ownership interests in Viper and Rattler change, adjustments to non-controlling interest and additional paid-in-capital, tax effected, will occur. Because these changes in the ownership interests in Viper and Rattler do not result in a change of control, the transactions are accounted for as equity transactions under ASC Topic 810, "Consolidation", which requires that any differences between the carrying value of the Company's basis in Viper and Rattler and the fair value of the consideration received are recognized directly in equity and attributed to the controlling interest. See Note 12—Capital Stock and Earnings Per Share for a discussion of changes of the Company's ownership interest in consolidated subsidiaries during the year ended December 31, 2020.

Revenue Recognition

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 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 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 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.

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.

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.

Prior-period performance obligations

The Company records revenue in the month production is delivered to the purchaser. However, purchaser and settlement statements for 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 years ended December 31, 2020, 2019 and 2018 revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material. The Company believes that the pricing provisions of its oil, natural gas and natural gas liquids contracts are customary in the industry. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the revenue related to expected sales volumes and prices for those properties are estimated and recorded.

Investments

An investment of less than 50% in an investee over which the Company exercises significant influence but does not have control is accounted for using the equity method. Additionally, an investment of greater than 50% in an investee over which the Company does not exercise significant influence or have control is also accounted for using the equity method. Under the equity method, the Company's share of the investee's earnings or loss is recognized in the consolidated statement of operations.

Judgment regarding the level of influence over each equity method investment includes considering key factors such as ownership interest, representation on the board of directors, participation in policy-making decisions, material intercompany transactions and extent of ownership by an investor in relation to the concentration of other shareholdings. Additionally, an investment in a limited liability company that maintains a specific ownership account for each investor shall be viewed as similar to an investment in a limited partnership for purposes of determining whether a noncontrolling investment shall be accounted for using the cost method or the equity method. The Company has determined it has the ability to exercise significant influence over its investments which constitute less than a 20% ownership interest, and does not have the ability to exercise significant influence over its investments which constitute greater than a 50% ownership interest, and therefore accounts for all of its investments under the equity method.

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. There were no material impairments for the Company's equity investments for the years ended December 31, 2020, 2019 and 2018. For additional information on the Company's investments, see Note 10—Equity Method Investments.

Accounting for Equity-Based Compensation

The Company has granted various types of stock-based awards including stock options and restricted stock units. Viper and Rattler have granted various unit-based awards including unit options and phantom units to employees, officers and directors of Viper's General Partner, Rattler's General Partner and the Company who perform services for the respective entities. These plans and related accounting policies for material awards are defined and described more fully in Note 13—Equity-Based Compensation. Equity compensation awards are measured at fair value on the date of grant and are expensed over the required service period. Forfeitures for these awards are recognized as they occur.

Environmental Compliance and Remediation

Environmental compliance and remediation costs, including ongoing maintenance and monitoring, are expensed as incurred. Liabilities are accrued when environmental assessments and remediation are probable, and the costs can be reasonably estimated.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (i) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (ii) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized. For additional information regarding income taxes, see Note 14—Income Taxes.

Recent Accounting Pronouncements

Recently Adopted Pronouncements

In June 2016, the Financial Accounting Standards Board (FASB) issued ASU 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. The Company adopted this update effective January 1, 2020. The adoption of this update did not have a material impact on the Company’s financial position, results of operations or liquidity since it does not have a history of credit losses.

Accounting Pronouncements Not Yet Adopted

In December 2019, the FASB issued ASU 2019-12, "Income Taxes (Topic 740) Simplifying the Accounting for Income Taxes", This update is intended to simplify the accounting for income taxes by removing certain exceptions and by clarifying and amending existing guidance. This update is effective for public business entities beginning after December 15, 2020 with early adoption permitted. The Company does not believe that the adoption of this update will have an impact on its financial position, results of operations or liquidity.

The Company considers the applicability and impact of all ASUs. ASUs not listed above were assessed and determined to be either not applicable or clarifications of ASUs previously disclosed.

3. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregation of Revenue

The following tables present the Company’s revenue from contracts with customers disaggregated by product type and basin:

	Year Ended December 31, 2020			
	Midland Basin	Delaware Basin	Other	Total
	(in millions)			
Oil sales	$ 1,393	$ 1,011	$ 6	$ 2,410
Natural gas sales	56	50	1	107
Natural gas liquid sales	138	100	1	239
Total	$ 1,587	$ 1,161	$ 8	$ 2,756

	Year Ended December 31, 2019			
	Midland Basin	Delaware Basin	Other	Total
	(in millions)			
Oil sales	$ 2,139	$ 1,351	$ 64	$ 3,554
Natural gas sales	32	33	1	66
Natural gas liquid sales	154	110	3	267
Total	$ 2,325	$ 1,494	$ 68	$ 3,887

	Year Ended December 31, 2018			
	Midland Basin	Delaware Basin	Other	Total
	(in millions)			
Oil sales	$ 1,350	$ 508	$ 21	$ 1,879
Natural gas sales	38	22	1	61
Natural gas liquid sales	140	47	3	190
Total	$ 1,528	$ 577	$ 25	$ 2,130

Customers

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the year ended December 31, 2020, four purchasers each accounted for more than 10% of our revenue: Vitol Inc. (“Vitol”) (26%); Shell Trading (USA) Company (“Shell”) (22%); Plains Marketing LP (“Plains”) (20%); and Trafigura Trading LLC (11%). For the year ended December 31, 2019, three purchasers each accounted for more than 10% of the Company’s revenue: Shell (27%); Plains (23%); and Vitol (15%). For the year ended December 31, 2018, three purchasers each accounted for more than 10% of the Company’s revenue: Shell (26%); Koch Supply & Trading LP (15%); and Occidental Energy Marketing Inc. (11%). The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

4. ACQUISITIONS AND DIVESTITURES

2020 Activity

Viper’s Acquisition of Certain Mineral and Royalty Interests

During the year ended December 31, 2020, Viper acquired, from unrelated third-party sellers, mineral and royalty interests representing 4,948 gross (417 net royalty) acres in the Permian Basin for an aggregate purchase price of approximately $64 million, subject to post-closing adjustments. Viper funded these acquisitions with cash on hand and borrowings under Viper LLC’s revolving credit facility.

Pending Acquisitions

See Note 18—Subsequent Events for acquisition agreements entered into in 2020 that are expected to close in 2021.

2019 Activity

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

On May 23, 2019, the Company completed its divestiture of 6,589 net acres of certain conventional and non-core Permian assets, which were acquired by the Company in its merger with Energen (as described below), for an aggregate sale price of $37 million. This divestiture did not result in a gain or loss because it did not have a significant effect on the Company’s reserve base or depreciation, depletion and amortization rate.

On July 1, 2019, the Company completed its divestiture of 103,750 net acres of certain conventional and non-core Permian assets, which were acquired by the Company in the merger with Energen (as described below), for an aggregate sale price of $285 million. This divestiture did not result in a gain or loss because it did not have a significant effect on the Company’s reserve base or depreciation, depletion and amortization rate.

2019 Drop-Down Transaction

On July 29, 2019, the Company entered into a definitive purchase agreement to divest certain mineral and royalty interests to Viper for approximately 18 million of Viper’s newly-issued Class B units, approximately 18 million newly-issued units of Viper LLC with a fair value of $497 million and $190 million in cash, after giving effect to closing adjustments for net title benefits (the “Drop-Down”). The mineral and royalty interests divested in the Drop-Down represent approximately

5,490 net royalty acres across the Midland and Delaware Basins, of which over 95% are operated by the Company, and have an average net royalty interest of approximately 3.2% (the “Drop-Down Assets”). The Drop-Down closed on October 1, 2019 and was effective as of July 1, 2019. Viper funded the cash portion of the purchase price of the Drop-Down Assets through a combination of cash on hand and borrowings under Viper LLC’s revolving credit facility.

2018 Activity

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.

Ajax Resources, LLC

On October 31, 2018, the Company completed its acquisition of leasehold interests and related assets of Ajax Resources, LLC, which included approximately 25,493 net leasehold acres in the Northern Midland Basin, for $900 million in cash and approximately 2.6 million shares of the Company’s common stock (the “Ajax acquisition”). This transaction was effective as of July 1, 2018. The cash portion of this transaction was funded through a combination of cash on hand, proceeds from the sale of mineral interests to Viper (described below under the caption “2018 Drop-Down Transaction”), borrowing under the Company’s revolving credit facility and a portion of the proceeds from the Company’s September 2018 senior note offering. See Note 11—Debt for information relating to this offering.

2018 Drop-down Transaction

On August 15, 2018, the Company completed a transaction to sell Viper mineral interests underlying 32,424 gross (1,696 net royalty) acres primarily in Pecos County, Texas, in the Permian Basin, approximately 80% of which are operated by the Company, for $175 million.

ExL Petroleum Management, LLC and EnergyQuest II LLC

On October 31, 2018, the Company completed its acquisitions of leasehold interests and related assets, one with ExL Petroleum Management, LLC and ExL Petroleum Operating, Inc. and one with EnergyQuest II LLC, for an aggregate of approximately 3,646 net leasehold acres in the Northern Midland Basin for a total of $313 million in cash. These transactions were effective as of August 1, 2018 and were funded through a combination of cash on hand, proceeds from the sale of assets to Viper and borrowing under the Company’s revolving credit facility.

Energen Corporation Merger

On November 29, 2018, the Company completed its acquisition of Energen in an all-stock transaction (the “Merger”), which was accounted for as a business combination. Upon completion of the Merger, 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 $7.1 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 long-term debt. See Note 11—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 allocation of the total purchase price of Energen to the identifiable assets acquired and the liabilities assumed based on the fair values at the acquisition date resulting in no goodwill or bargain purchase gain.

The following table sets forth the Company's purchase price allocation:

		(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	$	388
Asset retirement obligation		105
Long-term debt		1,099
Noncurrent derivative instruments		17
Deferred income taxes		1,425
Other long-term liabilities		7
Amount attributable to liabilities assumed	$	3,041
Fair value of assets acquired:		
Total current assets	$	298
Oil and natural gas properties		9,361
Midstream assets		253
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	$	10,177

The Company has included revenues of $102 million and direct operating expenses of $17 million in its consolidated statements of operations for the period from December 1, 2018 to December 31, 2018 due to the acquisition.

Pro Forma Financial Information

The following unaudited summary pro forma consolidated statement of operations data of Diamondback for the years ended December 31, 2018 and 2017 have been prepared to give effect to the Merger as if it had occurred on January 1, 2017. 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.

Additionally, pro forma earnings were adjusted to exclude acquisition-related costs incurred by the Company of approximately $37 million for the year ended December 31, 2018 and acquisition-related costs incurred by Energen of $59 million. 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, 2017 and is not intended to be a projection of future results.

	Year Ended December 31,	
	2018	2017
	(in millions, except per share amounts)	
Revenues	$ 3,532	$ 2,196
Income from operations	$ 1,559	$ 900
Net income	$ 1,320	$ 875
Basic earnings per common share	$ 7.54	$ 5.26
Diluted earnings per common share	$ 7.53	$ 5.24

5. VIPER ENERGY PARTNERS LP

Viper is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Global Select Market under the symbol "VNOM". Viper was formed by Diamondback to, among other things, own, acquire and exploit oil and natural gas properties in the Permian Basin in North America.

During the years ended December 31, 2020, 2019, and 2018, Diamondback received distributions of $62 million, $133 million and $155 million, respectively, in respect of its interests in Viper and Viper LLC.

Viper completed the following equity offerings during the years ended December 31, 2019 and 2018:

Date	Number of Units of Common Units Sold	Number of Units of Common Units Issued to Underwriters	Proceeds Received by Viper	Amount Repaid on Viper LLC's Credit Facility
			(in millions)	
July 2018	10,080,000	1,080,000	$ 303	$ 362
March 2019	10,925,000	1,425,000	$ 341	$ 314

There were no equity offerings during the year ended December 31, 2020.

The Company's ownership percentage in Viper is reflected as a non-controlling interest in the consolidated financial statements of Viper. The Company's ownership percentage in Viper changes as a result of Viper's public offerings, issuance of units for acquisitions, issuance of unit-based compensation, repurchases of common units and distribution equivalent rights paid on its units. These changes in ownership percentage and the disproportionate allocation of net income to the Company under Viper's partnership agreement for a set period of time following Viper's tax status change result in the difference between the Company's share of the underlying net book value in Viper before and after the respective Partnership common unit transactions. See Note 12—Capital Stock and Earnings Per Share for further details.

Recapitalization, Tax Status Election and Related Transactions by Viper

In March 2018, the Board of Directors of Viper's General Partner unanimously approved a change of Viper's federal income tax status from that of a pass-through partnership to that of a taxable entity via a "check the box" election. In connection with making this election, on May 9, 2018 Viper (i) amended and restated its First Amended and Restated Partnership Agreement, (ii) amended and restated the First Amended and Restated Limited Liability Company Agreement of 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 Viper 73,150,000 common units the Company owned in exchange for (i) 73,150,000 of Viper's newly-issued Class B units and (ii) 73,150,000 newly-issued units of the Operating Company pursuant to the terms of a Recapitalization Agreement dated March 28, 2018, as amended as of May 9, 2018 (the "Recapitalization Agreement"). Immediately following that exchange, Viper continued to be the managing member of the Operating Company, with sole control of its operations. The Operating Company units and Viper's Class B units owned by the Company are exchangeable from time to time for Viper'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, in connection with the change in Viper's income tax status becoming effective, the Company, among other things, exchanged 731,500 Class B units and 731,500 units in the Operating Company for 731,500 common units of Viper. After the effectiveness of the tax status election and the completion of related transactions, Viper's minerals business continues to be conducted through the Operating Company, which continues to be taxed as a partnership for federal and state income tax purposes. The Company is party to a partnership agreement and tax sharing agreement with Viper which govern the reimbursement of various expenses and state, local and other taxes, respectively. No significant transactions occurred under these agreements during the years ended December 31, 2020, 2019 and 2018.

Implementation of Viper's Common Unit Repurchase Program

On November 6, 2020, the board of directors of Viper's general partner approved an expansion of Viper's return of capital program with the implementation of a common unit repurchase program to acquire up to $100 million of Viper's outstanding common units through December 31, 2021. During the year ended December 31, 2020, Viper repurchased approximately $24 million of its common units under its repurchase program. As of December 31, 2020, $76 million remained available for use to repurchase Viper's common units under its common unit repurchase program.

Viper LLC's Revolving Credit Facility

Viper has entered into a secured revolving credit facility with Wells Fargo Bank, National Association, ("Wells Fargo") as administrative agent sole book runner and lead arranger. See Note 11—Debt for a description of this credit facility.

6. RATTLER MIDSTREAM LP

Rattler is a publicly traded Delaware limited partnership, the common units of which are listed on the Nasdaq Global Select Market under the symbol "RTLR". Rattler was formed by Diamondback in July 2018 to own, operate, develop and acquire midstream infrastructure assets in the Midland and Delaware Basins of the Permian Basin. Rattler Midstream GP LLC ("Rattler's General Partner"), a wholly owned subsidiary of Diamondback, serves as the general partner of Rattler. As of December 31, 2020, Diamondback owned approximately 72% of Rattler's total units outstanding.

Prior to the completion of Rattler's initial public offering (the "Rattler Offering") in May of 2019, Diamondback owned all of the general and limited partner interests in Rattler. The Rattler Offering consisted of 43,700,000 common units representing approximately 29% of the limited partner interests in Rattler at a price to the public of $17.50 per common unit. Rattler received net proceeds of approximately $720 million from the sale of these common units, after deducting offering expenses and underwriting discounts and commissions.

In connection with the completion of the Rattler Offering, Rattler (i) issued 107,815,152 Class B Units representing an aggregate 71% voting limited partner interest in Rattler in exchange for a $1 million cash contribution from Diamondback, (ii) issued a general partner interest in Rattler to Rattler's General Partner, in exchange for a $1 million cash contribution from Rattler's General Partner and (iii) caused Rattler LLC to make a distribution of approximately $727 million to Diamondback.

The Company is party to a partnership agreement, services and secondment agreement and tax sharing agreement with Rattler which govern the reimbursement of various expenses and state, local and other taxes, respectively. No significant transactions occurred under these agreements during the years ended December 31, 2020, 2019 and 2018.

Implementation of Rattler's Common Unit Repurchase Program

On October 29, 2020, the board of directors of Rattler's general partner approved a common unit repurchase program to acquire up to $100 million of Rattler's outstanding common units through December 31, 2021. During the year ended December 31, 2020, Rattler repurchased approximately $15 million of its common units under its repurchase program. As of December 31, 2020, $85 million remained available for use to repurchase common units under Rattler's common unit repurchase program.

Rattler LLC's Revolving Credit Facility

Rattler LLC has entered into a secured revolving credit facility with Wells Fargo, as administrative agent, sole book runner and lead arranger. See Note 11—Debt for a description of this credit facility.

7. REAL ESTATE ASSETS

In conjunction with Diamondback's acquisition of the Fasken Center, the Company allocated the $110 million purchase price between real estate assets and an insignificant amount of intangible lease assets related to in-place and above-market leases. The following schedules present the cost and related accumulated depreciation or amortization (as applicable) of Diamondback's real estate assets:

		December 31,	
	Estimated Useful Lives	**2020**	**2019**
	(Years)	**(in millions)**	
Buildings	20-30	$ 102	$ 102
Tenant improvements	15	5	5
Land	N/A	2	2
Land improvements	15	1	1
Total real estate assets		110	110
Less: accumulated depreciation		(13)	(9)
Total investment in land and buildings, net		$ 97	$ 101

8. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31,	
	2020	**2019**
	(in millions)	
Oil and natural gas properties:		
Subject to depletion	$ 19,884	$ 16,575
Not subject to depletion	7,493	9,207
Gross oil and natural gas properties	27,377	25,782
Accumulated depletion	(4,237)	(2,995)
Accumulated impairment	(7,954)	(1,934)
Oil and natural gas properties, net	15,186	20,853
Midstream assets	1,013	931
Other property, equipment and land	138	125
Accumulated depreciation	(123)	(74)
Total property and equipment, net	$ 16,214	$ 21,835
Balance of costs not subject to depletion:		
Incurred in 2020	$ 71	
Incurred in 2019	421	
Incurred in 2018	5,090	
Incurred in 2017	1,682	
Incurred in 2016	229	
Total not subject to depletion	$ 7,493	

Capitalized internal costs were approximately $53 million, $49 million and $29 million for the years ended December 31, 2020, 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 five years.

As a result of the decline in commodity prices during 2020, the Company recorded a non-cash ceiling test impairment for the year ended December 31, 2020 of $6.0 billion which is included in accumulated depletion, depreciation, amortization and impairment on the consolidated balance sheet. The impairment charge affected the Company's reported net income but did not reduce its cash flow. In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods. If the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters, the Company may have material write downs in subsequent quarters. The Company also recorded a non-cash ceiling test impairment on proved oil and natural gas properties of $790 million for the year ended December 31, 2019. No such impairment was recorded for the year ended December 31, 2018. Given the rate of change impacting the oil and natural gas industry described above, it is possible that circumstances requiring additional impairment testing will occur in future interim periods, which could result in potentially material impairment charges being recorded.

At December 31, 2020, there were $85 million in exploration costs and development costs and $51 million in capitalized interest that are not subject to depletion. At December 31, 2019, there were $228 million in exploration costs and development costs and $118 million capitalized interest that are not subject to depletion.

9. ASSET RETIREMENT OBLIGATIONS

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

	Year Ended December 31,	
	2020	2019
	(in millions)	
Asset retirement obligations, beginning of period	$ 94	$ 136
Additional liabilities incurred	13	8
Liabilities acquired	2	4
Liabilities settled and divested	(8)	(61)
Accretion expense	7	7
Revisions in estimated liabilities	1	—
Asset retirement obligations, end of period	109	94
Less: current portion(1)	1	—
Asset retirement obligations - long-term	$ 108	$ 94

(1) The current portion of the asset retirement obligation is included in other accrued liabilities in the Company's consolidated balance sheets.

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.

10. EQUITY METHOD INVESTMENTS

At December 31, 2020 and 2019, Rattler had the following investments:

	Ownership Interest	December 31, 2020	December 31, 2019
		(in millions)	
EPIC Crude Holdings, LP	10 %	$ 121	$ 110
Gray Oak Pipeline, LLC	10 %	130	115
Wink to Webster Pipeline LLC	4 %	83	34
OMOG JV LLC	60 %	194	219
Amarillo Rattler, LLC	50 %	5	1
Total		$ 533	$ 479

The following summarizes the income (loss) of equity method investees for the periods presented:

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(in millions)	
EPIC Crude Holdings, LP	$ (9)	$ (6)
Gray Oak Pipeline, LLC	10	1
Wink to Webster Pipeline LLC	(2)	(1)
OMOG JV LLC	(9)	—
Total	$ (10)	$ (6)

On February 1, 2019, Rattler LLC acquired a 10% equity interest in EPIC Crude Holdings, LP (“EPIC”), which owns and operates a pipeline (the “EPIC pipeline”) that transports crude oil and natural gas liquids across Texas for delivery into the Corpus Christi market. The EPIC pipeline became fully operational in April 2020.

On February 15, 2019, Rattler LLC acquired a 10% equity interest in Gray Oak Pipeline, LLC (“Gray Oak”), which owns and operates a pipeline (the “Gray Oak pipeline”) that transports crude oil from the Permian to Corpus Christi on the Texas Gulf Coast. The Gray Oak pipeline became fully operational in April 2020.

On March 29, 2019, Rattler LLC executed a short-term promissory note to Gray Oak. The note allowed for borrowing by Gray Oak of up to $123 million at a 2.52% interest rate with a maturity date of March 31, 2022. The short-term promissory note was repaid on May 31, 2019 and was terminated in the third quarter of 2020.

On July 30, 2019, Rattler LLC joined Wink to Webster Pipeline LLC as a 4% member, together with affiliates of ExxonMobil, Plains All American Pipeline, Delek US, MPLX LP and Lotus Midstream. The joint venture is developing a crude oil pipeline with origin points at Wink and Midland in the Permian Basin and delivery points at multiple Houston area locations (the “Wink to Webster pipeline”). The Wink to Webster pipeline’s main segment began interim service operation in the fourth quarter of 2020, and the joint venture is expected to begin full commercial operations in the fourth quarter of 2021. Upon completion, this pipeline will be capable of transporting approximately 1,500,000 Bbl/d.

On October 1, 2019, Rattler LLC acquired a 60% equity interest in OMOG JV LLC (“OMOG”). On November 7, 2019, OMOG acquired 100% of Reliance Gathering, LLC which owns and operates a crude oil gathering system in the Permian and was renamed as Oryx Midland Oil Gathering LLC following the acquisition. While Rattler’s equity interest is 60%, the investment is accounted for as an equity method investment as Rattler does not control operating activities and substantive participating rights exist with the controlling minority investor.

On December 20, 2019, Rattler LLC acquired a 50% equity interest in Amarillo Rattler LLC, which currently owns and operates the Yellow Rose gas gathering and processing system with estimated total processing capacity of 40,000 Mcf/d and over 84 miles of gathering and regional transportation pipelines in Dawson, Martin and Andrews Counties, Texas. This joint venture also intends to construct and operate a new 60,000 Mcf/d cryogenic natural gas processing plant in Martin

County, Texas, as well as incremental gas gathering and compression and regional transportation pipelines. However, development of the new processing plant has been postponed pending a recovery in commodity prices and activity levels. The Company has contracted for up to 30,000 Mcf/d of the capacity of the new processing plant pursuant to a gas gathering and processing agreement entered into with the joint venture in exchange for the Company's dedication of certain leasehold interests to that agreement. While Rattler's equity interest is 50%, the investment is accounted for as an equity method investment as Rattler does not control operating activities and substantive participating rights exist with the controlling investor.

Rattler reviews its investments to determine if a loss in value which is other than temporary has occurred. If such a loss has occurred, Rattler recognizes an impairment provision. No significant impairments were recorded for Rattler's equity method investments for the year ended December 31, 2020, 2019 or 2018. Rattler's investees all serve customers in the oil and natural gas industry, which has been experiencing economic challenges as described above. It is possible that prolonged industry challenges could result in circumstances requiring impairment testing, which could result in potentially material impairment charges in future interim periods.

11. DEBT

The Company's debt consisted of the following as of the dates indicated:

	December 31, 2020	December 31, 2019
	(in millions)	
4.625% Notes due 2021	$ 191	$ 399
7.320% Medium-term Notes, Series A, due 2022	20	21
2.875% Senior Notes due 2024	1,000	1,000
4.750% Senior Notes due 2025	500	—
5.375% Senior Notes due 2025	800	800
3.250% Senior Notes due 2026	800	800
7.350% Medium-term Notes, Series A, due 2027	—	11
7.125% Medium-term Notes, Series B, due 2028	100	108
3.500% Senior Notes due 2029	1,200	1,200
DrillCo Agreement	79	39
Unamortized debt issuance costs	(29)	(19)
Unamortized discount costs	(27)	(31)
Unamortized premium costs	15	9
Revolving credit facility(1)	23	13
Viper revolving credit facility(1)	84	97
Viper 5.375% Senior Notes due 2027	480	500
Rattler revolving credit facility(2)	79	424
Rattler 5.625% Senior Notes due 2025	500	—
Total debt, net	5,815	5,371
Less: current maturities of long-term debt	(191)	—
Total long-term debt	$ 5,624	$ 5,371

(1) Each of these revolving credit facilities matures on November 1, 2022.
(2) The Rattler revolving credit facility matures on May 28, 2024.

Debt maturities as of December 31, 2020, excluding debt issuance costs, premiums and discounts, are as follows:

Year Ending December 31,	Total
	(in millions)
2021	$ 191
2022	127
2023	—
2024	1,079
2025	1,800
Thereafter	2,659
Total	$ 5,856

Diamondback Notes

May 2020 Notes Offering

On May 26, 2020, the Company completed a notes offering of $500 million in aggregate principal amount of its 4.750% Senior Notes due 2025 (the "May 2020 Notes"). Interest on the May 2020 Notes accrues from May 26, 2020, and is payable in cash semi-annually on May 31 and November 30 of each year, beginning November 30, 2020. The May 2020 Notes mature on May 31, 2025. The Company received net proceeds of approximately $496 million from the offering of the May 2020 Notes. The May 2020 Notes are the Company's senior unsecured obligations and are guaranteed by Diamondback O&G LLC (the "Guarantor"), but are not guaranteed by any of the Company's other subsidiaries. The May 2020 Notes are senior in right or payment to any of the Company's and the Guarantor's future subordinated indebtedness and rank equal in right of payment with all of the Company's and the Guarantor's existing and future senior indebtedness. The May 2020 Notes are effectively subordinated to the Company's and the Guarantor's existing and future secured indebtedness, if any, to the extent of the value of the collateral securing such indebtedness, and structurally subordinated to all of the existing and future indebtedness and other liabilities of the Company's subsidiaries other than the Guarantor.

4.750% Senior Notes

On October 28, 2016, the Company issued $500 million in aggregate principal amount of 4.750% senior notes due 2024 ("4.750% senior notes"), under an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee. On September 25, 2018, the Company issued $750 million aggregate principal amount of new 4.750% senior notes as additional notes under, and subject to the terms of, the same indenture governing the 4.750% senior notes.

On December 20, 2019, the Company redeemed all of the outstanding 4.750% senior notes, which included $1.25 billion of aggregate outstanding principal at a redemption price of 103.563% plus accrued and unpaid interest on the outstanding principal amount to the Redemption Date, resulting in a loss on extinguishment of debt of $56 million. On December 5, 2019, the indenture governing the 4.750% senior notes was fully satisfied and discharged and the guarantors were released from their guarantees of the 4.750% senior notes. The Company funded the redemption with a portion of the net proceeds from the issuance of the December 2019 Notes.

2025 Senior Notes

On December 20, 2016, the Company issued $500 million in aggregate principal amount of 5.375% senior notes due 2025, under an indenture among us, the subsidiary guarantors party thereto and Wells Fargo, as the trustee (the "2025 indenture"). On January 29, 2018, the Company issued an additional $300 million aggregate principal amount of new 5.375% senior notes due 2025 as additional notes under the 2025 indenture and received approximately $308 million in net proceeds, after deducting discounts and offering expenses, but disregarding accrued interest. The Company used these net proceeds to repay a portion of the outstanding borrowings under its revolving credit facility. Collectively, the aggregate $800 million principal amount of 5.375% senior notes due in 2025 are referred to as the 2025 senior notes.

All of the 2025 senior notes will mature on May 31, 2025 and the 5.375% per annum interest is payable semi-annually, in arrears on May 31 and November 30 each year. Currently, the 2025 senior notes are not guaranteed by any of the

Company's subsidiaries other than its restricted subsidiary, Diamondback O&G LLC, and will not be guaranteed by any of the Company's future unrestricted subsidiaries. These notes may be guaranteed by future restricted 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.

December 2019 Notes Offering

On December 5, 2019, the Company issued $1.0 billion in aggregate principal amount of 2.875% senior notes due 2024 (the "2024 notes"), $800 million in aggregate principal amount of 3.250% senior notes due 2026 (the "2026 notes"), and $1.2 billion aggregate principal amount of 3.500% senior notes due 2029, (the "2029 notes" and, together with the 2024 notes and the 2026 notes, the "December 2019 Notes"). The 2024 notes will mature on December 1, 2024, the 2026 notes will mature on December 1, 2026 and the 2029 notes will mature on December 1, 2029. Interest will accrue and be payable semi-annually, in arrears on June 1 and December 1 of each year, commencing on June 1, 2020. The December 2019 Notes are fully and unconditionally guaranteed by Diamondback O&G LLC and are not guaranteed by any of the Company's other subsidiaries.

The December 2019 Notes were issued under an indenture, dated as of December 5, 2019, among the Company and Wells Fargo, as the trustee, as supplemented by the first supplemental indenture dated as of December 5, 2019 (the "December 2019 Notes Indenture").

The Company may redeem (i) the 2024 Notes in whole or in part at any time prior to November 1, 2024 (one month prior to the maturity date of the 2024 Notes), (ii) the 2026 Notes in whole or in part at any time prior to October 1, 2026 (two months prior to the maturity date of the 2026 Notes) and (iii) the 2029 Notes in whole or in part at any time prior to September 1, 2029 (three months prior to the maturity date of the 2029 Notes) (each such date, a "par call date"), in each case at the redemption price set forth in the indenture governing the December 2019 Notes. If any of the December 2019 Notes are redeemed on or after their respective par call dates, in each case, they will be redeemed at a redemption price equal to 100% of the principal amount plus interest accrued thereon up to but not including the redemption date.

Upon the occurrence of a Change of Control Triggering Event (as defined in the indenture governing the December 2019 Notes), holders may require the Company to purchase some or all of their December 2019 Notes for cash at a price equal to 101% of the principal amount of the December 2019 Notes being purchased, plus accrued and unpaid interest, if any, to the date of purchase.

The indenture governing the December 2019 Notes contains customary terms and covenants, including limitations on the Company's ability and the ability of certain of its subsidiaries to incur liens securing funded indebtedness and on the Company's ability to consolidate, merge or sell, convey, transfer or lease all or substantially all of its assets.

Second Amended and Restated 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. On June 28, 2019, the credit agreement was amended pursuant to an eleventh amendment, which implemented certain changes to the credit facility for the period on and after the date on which our unsecured debt achieves an investment grade rating from two rating agencies and certain other conditions in the credit agreement are satisfied (the "investment grade changeover date"). On November 20, 2019, Diamondback O&G LLC caused Diamondback O&G LLC to deliver a notice as borrower under the revolving credit facility to trigger the "investment grade changeover date." As of December 31, 2020, the maximum credit amount available under the credit agreement is $2.0 billion. As of December 31, 2020, the Company had approximately $23 million of outstanding borrowings under its revolving credit facility and $1.98 billion available for future borrowings under the revolving credit facility. As of December 31, 2020, there was an aggregate of $3 million in letters of credit outstanding under the credit agreement, which reduce available borrowings on a dollar for dollar basis.

Diamondback O&G LLC is the borrower under the credit agreement and, as of December 31, 2020, the credit agreement is guaranteed by Diamondback Energy, Inc. None of the Company's other subsidiaries are guarantors under the revolving credit facility.

The outstanding borrowings under the credit agreement bear interest at a per annum rate elected by us that is equal to the 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 with range from 0.125% to 1.0% per annum and from 1.125% to 2.0% per annum in the case of LIBOR, in each case, depending on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt. We are obligated to pay a quarterly commitment fee ranging from 0.125% to 0.350% per year on the unused portion of the commitment, based on the pricing level, which in turn depends on the rating agencies' rating of our unsecured debt. The weighted average interest rates on the credit facility were 2.02%, 4.10% and 3.75% for the years ended December 31, 2020, 2019 and 2018, respectively.

Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage). Loan principal is required to be repaid (a) to the extent the loan amount exceeds the commitment due to any termination or reduction of the aggregate maximum credit amount and (b) at the maturity date of November 1, 2022.

The credit agreement contains a financial covenant that requires us to maintain a Total Net Debt to Capitalization Ratio (as defined in the credit agreement) of no more than 65%. Our non-guarantor restricted subsidiaries may incur debt for borrowed money in an aggregate principal amount up to 15% of consolidated net tangible assets (as defined in the credit agreement) and we and our restricted subsidiaries may incur liens if the aggregate amount of debt secured by such liens does not exceed 15% of consolidated net tangible assets.

As of December 31, 2020 and 2019, the Company was in compliance with all financial maintenance covenants under the revolving credit facility, as then in effect. 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.

Energen Notes

At the effective time of the Merger, Energen became the Company's wholly owned subsidiary and remained the issuer of an aggregate principal amount of $530 million in notes (the "Energen Notes"), issued under an indenture dated September 1, 1996 with The Bank of New York as Trustee (the "Energen Indenture"). As of December 31, 2020, the aggregate principal amount of the Energen Notes had been reduced to $311 million, consisting of: (1) $191 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 and (3) $20 million of 7.32% notes due on July 28, 2022.

The Company used the net proceeds from the offering of May 2020 Notes, among other things, to make an equity contribution to Energen to purchase $209 million in previously outstanding aggregate principal amount of Energen's 4.625% senior notes pursuant to a tender offer.

During the third quarter of 2020, the Company repurchased $10 million in principal amount of the outstanding Energen 7.35% medium-term notes due on July 28, 2027 at a price of 120% of the aggregate principal amount, which resulted in an immaterial loss on extinguishment of debt.

The Energen Notes are the senior unsecured obligations of Energen and, post-merger, Energen, as a 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 if any, and are effectively subordinated to Energen's senior secured indebtedness, if any, to the extent of the value of the collateral securing such indebtedness. None of the Company's other subsidiaries guarantee the Energen Notes.

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 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.

Viper's Credit Agreement

On July 20, 2018, Viper LLC, as borrower, entered into an amended and restated credit agreement with Viper, as guarantor, Wells Fargo, as administrative agent, and the other lenders. The credit agreement, as amended (the "Viper credit agreement"), provides for a revolving credit facility in the maximum credit amount of $2.0 billion and a borrowing base based on Viper LLC's oil and natural gas reserves and other factors (the "borrowing base") of $580 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, Viper LLC and Wells Fargo each may request up to three interim redeterminations of the borrowing base during any 12-month period. The borrowing base was reaffirmed at $580 million by the lenders during the regularly scheduled (semi-annual) fall 2020 redetermination in November 2020. As of December 31, 2020, Viper LLC had $84 million of outstanding borrowings and $496 million available for future borrowings under the Viper credit agreement. The weighted average interest rates on borrowings under the Viper credit agreement were 2.20%, 4.51%, and 4.37% for the years ended December 31, 2020, 2019 and 2018, respectively.

The outstanding borrowings under the Viper credit agreement bear interest at a per annum rate elected by Viper LLC 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. Viper LLC 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 Viper and Viper LLC.

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 Viper credit agreement	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined the Viper 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 $1.0 billion 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 December 31, 2020, Viper LLC was in compliance with all financial maintenance covenants under the Viper credit agreement, as then in effect. The lenders may accelerate all of the indebtedness under the Viper credit agreement upon the occurrence and during the continuance of any event of default. The Viper 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 the credit agreement generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

Viper's Notes

On October 16, 2019, Viper completed an offering in which it issued its 5.375% Senior Notes due 2027 in aggregate principal amount of $500 million (the "Viper Notes"). Viper received gross proceeds of $500 million from the such offering, which it loaned to Viper LLC. Viper LLC paid the expenses of the offering, resulting in net proceeds of the offering of $490 million, which Viper LLC used to pay down borrowings under the Viper credit agreement.

The Viper Notes were issued under an indenture, dated as of October 16, 2019, among Viper, as issuer, Viper LLC, as guarantor and Wells Fargo, as trustee (the "Viper Indenture"). Pursuant to the Viper Indenture and the Viper Notes, interest on the Viper Notes accrues at a rate of 5.375% per annum on the outstanding principal amount thereof, payable semi-annually on May 1 and November 1 of each year, commencing on May 1, 2020. The Viper Notes will mature on November 1, 2027.

During the year ended December 31, 2020, Viper repurchased $20 million of outstanding principal of the Viper notes at a cash price ranging from 97.5% to 98.5% of the aggregate principal amount, which resulted in an immaterial gain on extinguishment of debt, and $480 million in aggregate principal amount remained outstanding at December 31, 2020.

Viper LLC guarantees the Viper Notes pursuant to the Viper Indenture. Neither the Company nor any of its other subsidiaries guarantee the Viper Notes.

The Viper Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit Viper's ability and the ability of its restricted subsidiaries to incur or guarantee additional indebtedness or issue certain redeemable or preferred equity, make certain investments, declare or pay dividends or make distributions on equity interests or redeem, repurchase or retire equity interests or subordinated indebtedness, transfer or sell assets, agree to payment restrictions affecting its restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens and designate certain of its subsidiaries as unrestricted subsidiaries. These covenants are subject to numerous exceptions, some of which are material. Certain of these covenants are subject to termination upon the occurrence of certain events.

Rattler's Credit Agreement

In connection with the Rattler Offering, Rattler, as parent, and Rattler LLC, as borrower, entered into a credit agreement, dated May 28, 2019, with Wells Fargo, as administrative agent, and a syndicate of banks, as lenders party thereto (the "Rattler credit agreement").

The Rattler credit agreement provides for a revolving credit facility in the maximum credit amount of $600 million. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid at the maturity date of May 28, 2024. The Rattler credit agreement is guaranteed by Rattler, Tall City, Rattler OMOG LLC and Rattler Ajax Processing LLC. As of December 31, 2020, Rattler LLC had $ 79 million of outstanding borrowings and $521 million available for future borrowings under the Rattler credit agreement. The weighted average interest rates on borrowings under the Rattler credit agreement were 2.10% and 3.13% for the years ended December 31, 2020 and 2019, respectively.

The outstanding borrowings under the Rattler credit agreement bear interest at a per annum rate elected by Rattler LLC that is based on the prime rate or LIBOR, in each case plus an applicable margin. The applicable margin ranges from 0.250% to 1.250% per annum for prime-based loans and 1.250% to 2.250% per annum for LIBOR loans, in each case depending on the Consolidated Total Leverage Ratio (as defined in the Rattler credit agreement). Rattler LLC is obligated to pay a quarterly commitment fee ranging from 0.250% to 0.375% per annum on the unused portion of the commitment, which fee is also dependent on the Consolidated Total Leverage Ratio.

The Rattler credit agreement contains various affirmative and negative covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, distributions and other restricted payments, transactions with affiliates, and entering into certain swap agreements, in each case of Rattler, Rattler LLC and their restricted subsidiaries. The covenants are subject to exceptions set forth in the Rattler credit agreement, including an exception allowing Rattler LLC or Rattler to issue unsecured debt securities and an exception allowing payment of distributions if no default exists. The Rattler credit agreement may be used to fund capital expenditures, to finance working capital, for general company purposes, to pay fees and expenses related to the credit agreement, and to make distributions permitted under the Rattler credit agreement.

The Rattler credit agreement also contains financial maintenance covenants that require the maintenance of the financial ratios described below:

Financial Covenant	Required Ratio
Consolidated Total Leverage Ratio commencing with the fiscal quarter ending September 30, 2019	Not greater than 5.00 to 1.00 (or not greater than 5.50 to 1.00 for 3 fiscal quarters following certain acquisitions), but if the Consolidated Senior Secured Leverage Ratio (as defined in the Rattler credit agreement) is applicable, then not greater than 5.25 to 1.00)
Consolidated Senior Secured Leverage Ratio commencing with the last day of any fiscal quarter in which the Financial Covenant Election (as defined in the Rattler credit agreement) is made	Not greater than 3.50 to 1.00
Consolidated Interest Coverage Ratio (as defined in the Rattler credit agreement) commencing with the fiscal quarter ending September 30, 2019	Not less than 2.50 to 1.00

As of December 31, 2020, Rattler LLC was in compliance with all financial maintenance covenants under the Rattler credit agreement. The lenders may accelerate all of the indebtedness under the Rattler credit agreement upon the occurrence and during the continuance of any event of default. The Rattler credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change in control.

Rattler's Notes

On July 14, 2020, Rattler completed an offering of $500 million in aggregate principal amount of its 5.625% Senior Notes due 2025, (the "Rattler Notes"). The Rattler Notes mature on July 15, 2025, and interest on the Rattler Notes is payable on January 15 and July 15 of each year, beginning on January 15, 2021. Rattler received net proceeds of approximately $490 million from the Rattler Notes and loaned the gross proceeds to Rattler LLC to repay then outstanding borrowings under the Rattler Credit Agreement. The Rattler Notes are senior unsecured obligations of Rattler, rank equally in right of payment with all of Rattler's existing and future senior indebtedness and initially are guaranteed on a senior unsecured basis by Rattler LLC, Tall City, Rattler OMOG LLC and Rattler Ajax Processing LLC. Neither the Company nor Rattler's General Partner guarantee the Rattler Notes. In the future, each of Rattler's restricted subsidiaries that either (1) guarantees any of its or a guarantor's other indebtedness or (2) is classified as a domestic restricted subsidiary under the indenture governing the Rattler Notes and is an obligor with respect to any indebtedness under any credit facility will be required to guarantee the Rattler Notes.

The indenture under which the Rattler Notes were issued contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit Rattler's ability and the ability of its restricted subsidiaries to incur or guarantee additional indebtedness or issue certain redeemable or preferred equity, make certain investments, declare or pay dividends or make distributions on equity interests or redeem, repurchase or retire equity interests or subordinated indebtedness, transfer or sell assets, agree to payment restrictions affecting its restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens and designate certain of its subsidiaries as unrestricted subsidiaries. These covenants are subject to numerous exceptions, some of which are material. Certain of these covenants are subject to termination upon the occurrence of certain events.

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 December 31, 2020, the amount due to CEMOF related to this alliance was $79 million. As of December 31, 2020, fifteen joint wells have been drilled and completed.

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Interest expense	$ 250	$ 235	$ 110
Other fees and expenses	6	4	10
Less: interest income	4	1	1
Less: capitalized interest	55	66	32
Interest expense, net	$ 197	$ 172	$ 87

12. CAPITAL STOCK AND EARNINGS PER SHARE

The Company did not complete any equity offerings during the years ended December 31, 2020, 2019 and 2018.

Viper Equity Offerings

For information regarding Viper's completed equity offerings during the years ended December 31, 2019 and 2018, refer to Note 5—Viper Energy Partners LP.

Rattler's Initial Public Offering

For information regarding Rattler's initial public offering during the year ended December 31, 2019, refer to Note 6—Rattler Midstream LP.

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. Purchases under the repurchase program were made from time to time in open market or privately negotiated transactions, and were subject to market conditions, applicable legal requirements, contractual obligations and other factors. The repurchase program did not require the Company to acquire any specific number of shares. During the years ended December 31, 2020 and 2019, the Company repurchased $98 million and $598 million, respectively, of its common stock under the repurchase program. The repurchase program was suspended beginning in the first quarter of 2020 and expired on December 31, 2020.

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, the per share earnings of Viper and Rattler are included in the consolidated earnings per share computation based on the consolidated group's holdings of the subsidiaries.

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

	Year Ended December 31,		
	2020	2019	2018
	(In millions, except per share amounts, shares in thousands)		
Net income (loss) attributable to common stock	$ (4,517)	$ 240	$ 846
Weighted average common shares outstanding:			
Basic weighted average common units outstanding	157,976	163,493	104,622
Effect of dilutive securities:			
Potential common shares issuable(1)	—	350	307
Diluted weighted average common shares outstanding	157,976	163,843	104,929
Basic net income (loss) attributable to common stock	$ (28.59)	$ 1.47	$ 8.09
Diluted net income (loss) attributable to common stock	$ (28.59)	$ 1.47	$ 8.06

(1) For the year ended December 31, 2020, there were 696,223 potential common shares excluded from the computation of diluted earnings per share because their inclusion would have been anti-dilutive due to recording a net loss.

Change in Ownership of Consolidated Subsidiaries

The following table summarizes changes in the ownership interest in consolidated subsidiaries during the period:

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Net income (loss) attributable to the Company	$ (4,517)	$ 240	$ 846
Change in ownership of consolidated subsidiaries(1)	358	(33)	150
Change from net income (loss) attributable to the Company's stockholders and transfers to non-controlling interest	$ (4,159)	$ 207	$ 996

(1) The year ended December 31, 2020 includes an adjustment to non-controlling interest for Rattler of $329 million and to additional paid-in-capital of $329 million to reflect the ownership structure that was effective at June 30, 2020. The adjustment had no impact on earnings.

13. EQUITY-BASED COMPENSATION

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

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
General and administrative expenses	$ 37	$ 48	$ 27
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	$ 16	$ 17	$ 10

Restricted Stock Units

Under the Equity Plan, approved by the Board of Directors, the Company is authorized to issue restricted stock and restricted stock units to eligible employees. The Company estimates the fair values of restricted stock awards and units as the closing price of the Company’s common stock on the grant date of the award, which is expensed over the applicable vesting period.

The following table presents the Company's restricted stock awards and units activity under the Equity Plan during the year ended December 31, 2020:

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2019	505,867	$ 96.01
Granted	921,730	$ 35.38
Vested	(283,330)	$ 86.81
Forfeited	(30,787)	$ 80.94
Unvested at December 31, 2020	1,113,480	$ 48.58

The aggregate fair value of restricted stock units that vested during the years ended December 31, 2020, 2019 and 2018 was $25 million, $45 million and $19 million, respectively. As of December 31, 2020, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $41 million. Such cost is expected to be recognized over a weighted-average period of 2.3 years.

During the year ended December 31, 2020, the Company modified an insignificant amount of restricted stock units to include dividend equivalent rights during the vesting period which did not result in any incremental compensation costs.

Performance-Based Restricted Stock Units

To provide long-term incentives for 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 February 2018, eligible employees received performance restricted stock unit awards totaling 117,423 units from which a minimum of 0% and a maximum of 200% units could be awarded based upon the TSR during the performance period of January 1, 2018 to December 31, 2020, subject to continued employment. All remaining awards under this grant cliff vested at December 31, 2020.

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 based upon the TSR during the performance period of January 1, 2019 to December 31, 2021 and cliff vest at December 31, 2021 subject to continued employment. 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.

In March 2020, eligible employees received performance restricted stock unit awards totaling 225,047 units from which a minimum of 0% and a maximum of 200% units could be awarded based upon the TSR during the three-year performance period of January 1, 2020 to December 31, 2022 and cliff vest at December 31, 2022 subject to continued employment. The initial payout of the March 2020 awards will be further adjusted by a TSR modifier that may reduce the payout or increase the payout up to a maximum of 250%.

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:

	2020	2019	2018
Grant-date fair value	$ 70.17	$ 137.22	$ 170.45
Grant-date fair value (5-year vesting)		$ 132.48	
Risk-free rate	0.86 %	2.55 %	1.99 %
Company volatility	36.70 %	35.00 %	35.90 %

The following table presents the Company's performance restricted stock unit activity under the Equity Plan for the year ended December 31, 2020:

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2019	271,819	$ 147.07
Granted[(1)]	281,519	$ 88.41
Vested	(133,355)	$ 139.43
Forfeited	(8,396)	$ 170.45
Unvested at December 31, 2020[(2)]	411,587	$ 99.10

(1) Includes units granted to satisfy the final payout of vested performance restricted stock units based on the TSR ranking for the performance period.
(2) A maximum of 935,698 units could be awarded based upon the Company's final TSR ranking.

As of December 31, 2020, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $22 million, which is expected to be recognized over a weighted-average period of 2.1 years.

Rattler Long-Term Incentive Plan

On May 22, 2019, the board of directors of Rattler's General Partner adopted the Rattler Midstream LP Long Term Incentive Plan ("Rattler LTIP"), for employees, consultants and directors of Rattler's General Partner and any of its affiliates, including Diamondback, who perform services for Rattler. The Rattler LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards.

Under the Rattler LTIP, the board of directors of Rattler's General Partner is authorized to issue phantom units to eligible employees and non-employee directors. Rattler estimates the fair value of phantom units as the closing price of Rattler's common units on the grant date of the award, which is expensed over the applicable vesting period. Upon vesting, the phantom units entitle the recipient to one common unit of Rattler for each phantom unit. The recipients are also entitled to distribution equivalent rights, which represent the right to receive a cash payment equal to the value of the distributions paid on one phantom unit between the grant date and the vesting date.

The following table presents the phantom unit activity under the Rattler LTIP for the year ended December 31, 2020:

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2019	2,226,895	$ 19.14
Granted	348,379	$ 6.51
Vested	(460,781)	$ 19.06
Forfeited	(24,825)	$ 17.54
Unvested at December 31, 2020	2,089,668	$ 17.07

The aggregate fair value of phantom units that vested during the year ended December 31, 2020 was $9 million. As of December 31, 2020, the unrecognized compensation cost related to unvested phantom units was $30 million which is expected to be recognized over a weighted-average period of 3.2 years.

14. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The Company is subject to corporate income taxes and the Texas margin tax. The Company and its subsidiaries, other than Viper, Viper LLC, Rattler and Rattler LLC, file a federal corporate income tax return on a consolidated basis. As discussed further below, Viper is a taxable entity for federal income tax purposes effective May 10, 2018, and as such files a federal corporate income tax return including the activity of its investment in Viper LLC. Subsequent to Rattler's election to be treated as a corporation for federal income tax purposes effective May 24, 2019, Rattler is also a taxable entity and as such files a federal corporate income tax return including the activity of its investment in Rattler LLC. Viper's and Rattler's provision for income taxes is included in the Company's consolidated income tax provision and, to the extent applicable, in net income attributable to the non-controlling interest.

The Company's effective income tax rates were 19.1%, 13.0% and 15.1% for the years ended December 31, 2020, 2019 and 2018, respectively. Total income tax benefit for the year ended December 31, 2020 differed from amounts computed by applying the United States federal statutory tax rate to pre-tax loss for the period primarily due to the impact of recording a valuation allowance on Viper's deferred tax assets, partially offset by state income taxes net of federal benefit and by tax benefit resulting from the carryback of federal net operating losses. Total income tax expense for the year ended December 31, 2019 differed from amounts computed by applying the United States federal statutory rate to pre-tax income for the period primarily due to the impact of deferred taxes recognized as a result of Viper's change in tax status and state income taxes net of federal benefit. Total income tax expense for the year ended December 31, 2018 differed from amounts computed by applying the United States federal statutory rate to pre-tax income for the period primarily due to the impact of deferred taxes recognized as a result of Viper's change in tax status, net income attributable to the noncontrolling interest, and state income taxes net of federal benefit.

The Coronavirus Aid, Relief, and Economic Security Act ("CARES Act") was enacted on March 27, 2020. This legislation included a number of provisions applicable to U.S. income taxes for corporations, including providing for carryback of certain net operating losses, accelerated refund of minimum tax credits, and modifications to the rules limiting the deductibility of business interest expense. The Company considered the impact of this legislation in the period of enactment, resulting in current income tax benefit of $62 million, offset by deferred income tax expense of $38 million, for the year ended December 31, 2020 related to the carryback of approximately $179 million of the Company's federal net operating losses to tax years in which the corporate income tax rate was 35%. Prior to the enactment of the CARES Act in the first quarter of 2020, there was no tax refund available to the Company with respect to its losses, resulting in deferred tax assets associated with federal net operating loss carryforwards at the statutory 21% corporate income tax rate. As a result of the refund associated with such carryback as well as the accelerated refund available for minimum tax credits, the Company's current federal taxes receivable totaled approximately $100 million as of December 31, 2020.

The components of the Company's consolidated provision for income taxes from continuing operations for the years ended December 31, 2020, 2019 and 2018 are as follows:

	Year Ended December 31,		
	2020	2019	2018
		(In millions)	
Current income tax provision (benefit):			
Federal	$ (62)	$ —	$ —
State	—	—	—
Total current income tax provision (benefit)	(62)	—	—
Deferred income tax provision (benefit):			
Federal	(1,010)	40	160
State	(32)	7	8
Total deferred income tax provision (benefit)	(1,042)	47	168
Total provision for (benefit from) income taxes	$ (1,104)	$ 47	$ 168

A reconciliation of the statutory federal income tax amount from continuing operations to the recorded expense is as follows:

	Year Ended December 31,		
	2020	2019	2018
		(In millions)	
Income tax expense at the federal statutory rate (21%)	$ (1,213)	$ 76	$ 234
Impact of nontaxable noncontrolling interest	—	—	(5)
Income tax benefit relating to net operating loss carryback	(25)	—	—
State income tax expense, net of federal tax effect	(30)	6	8
Non-deductible compensation	6	4	5
Change in valuation allowance	153	—	—
Deferred taxes related to change in Viper LP's tax status	—	(42)	(73)
Other, net	5	3	(1)
Provision for (benefit from) income taxes	$ (1,104)	$ 47	$ 168

The components of the Company's deferred tax assets and liabilities as of December 31, 2020 and 2019 are as follows:

	December 31,	
	2020	2019
	(In millions)	
Deferred tax assets:		
Net operating loss and other carryforwards	$ 524	$ 453
Derivative instruments	60	—
Stock based compensation	7	7
Viper's investment in Viper LLC	150	134
Rattler's investment in Rattler LLC	58	—
Other	8	11
Deferred tax assets	807	605
Valuation allowance	(166)	(7)
Deferred tax assets, net of valuation allowance	641	598
Deferred tax liabilities:		
Oil and natural gas properties and equipment	1,156	2,275
Midstream investments	192	50
Derivative instruments	—	6
Rattler's investment in Rattler LLC	—	8
Other	3	3
Total deferred tax liabilities	1,351	2,342
Net deferred tax liabilities	$ 710	$ 1,744

The Company had net deferred tax liabilities of approximately $0.7 billion and $1.7 billion at December 31, 2020 and 2019, respectively. On November 29, 2018, the Company completed its acquisition of Energen. For federal income tax purposes, the acquisition was a tax-free merger whereby the Company's tax basis in Energen assets and liabilities was unaffected by the acquisition. As of December 31, 2019, the Company had completed its purchase price allocation for the acquisition, including a deferred tax liability of $1.4 billion associated with the acquired assets.

The Company incurred a tax net operating loss ("NOL") in the current year due principally to the ability to expense certain intangible drilling and development costs under current law. There is no tax refund available to the Company as a result of its loss, nor is there any current federal income tax payable. At December 31, 2020, the Company had approximately $0.4 billion of federal NOLs expiring in 2032 through 2037 and $1.9 billion of federal NOLs with an indefinite carryforward life, including NOLs acquired from Energen. The Company principally operates in the state of Texas and is subject to Texas Margin Tax, which currently does not include an NOL carryover provision. The Company's federal tax attributes acquired from Energen are subject to an annual limitation under Section 382 of the Internal Revenue Code of 1986, as amended, which relates to tax attribute limitations upon the 50% or greater change of ownership of an entity during any three-year look back period. The Company believes that the application of Section 382 will not have an adverse effect on future usage of the Company's NOLs and credits.

In addition to the carryback of certain of the Company's federal NOLs pursuant to the CARES Act as noted above, modifications to the rules regarding deductibility of business interest expense resulting from enactment of the CARES Act and from the issuance of final regulations by the U.S. Department of Treasury in July 2020 resulted in a reduction to carryforwards of the Company's business interest expense and corresponding increase to its federal net operating loss carryforwards.

As of December 31, 2020, the Company had a valuation allowance of $5 million primarily related to certain state NOL carryforwards which the Company does not believe are realizable as it does not anticipate future operations in those states and a valuation allowance of $161 million related to Viper's deferred tax assets, as discussed further below. Management's assessment at each balance sheet date included consideration of all available positive and negative evidence including the anticipated timing of reversal of deferred tax liabilities. Management believes that the balance of the Company's NOLs are realizable to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. As of December 31, 2020, management determined that it is more likely than not that the Company will realize its remaining deferred tax assets.

As discussed further in Note 5—Viper Energy Partners LP, on March 29, 2018, Viper announced that the Board of Directors of its General Partner had unanimously approved a change of Viper's federal income tax status from that of a pass-through partnership to that of a taxable entity, which change became effective on May 10, 2018. The transactions undertaken in connection with the change in Viper's tax status were not taxable to the Company. Subsequent to Viper's change in tax status, Viper'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.

At December 31, 2020, the Company's net deferred tax liabilities include deferred tax assets of approximately $11 million related to Viper's NOL carryforwards and approximately $150 million related to Viper's investment in Viper LLC, approximately $115 million of which was recorded as a result of Viper's change in tax status. Based on information available regarding unitholders; tax basis, Viper revised its estimate of the difference between its tax basis and its basis for financial accounting purposes in Viper LLC on the date of the tax status change, resulting in deferred income tax benefit of $42 million and $73 million included in the Company's consolidated income tax provision for the years ended December 31, 2019 and 2018, respectively. As of December 31, 2020, Viper had federal NOL carryforwards of approximately $50 million which may be carried forward indefinitely to offset future taxable income.

As of December 31, 2020, Viper had a valuation allowance of approximately $161 million related to deferred tax assets that Viper does not believe are more likely than not to be realized. Management considers the likelihood that Viper's NOLs and other deferred tax attributes will be utilized prior to their expiration, if applicable. The determination to record a valuation allowance was based on Management's assessment of all available evidence, both positive and negative, supporting realizability of Viper's deferred tax assets as required by applicable accounting standards. In light of those criteria for recognizing the tax benefit of deferred tax assets, the assessment resulted in application of a valuation allowance against Viper's federal deferred tax assets as of March 31, 2020 and subsequent balance sheet dates within the year ended December 31, 2020.

As discussed further in Note 6—Rattler Midstream LP, on May 28, 2019, Rattler completed its initial public offering. Even though Rattler is organized as a limited partnership under state law, Rattler is subject to U.S. federal and state income tax at corporate rates, subsequent to the effective date of Rattler's election to be treated as a corporation for U.S. federal income tax purposes. As such, Rattler'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.

At December 31, 2020, the Company's net deferred tax liabilities include a deferred tax asset of approximately $58 million related to Rattler's investment in Rattler LLC. In the second quarter of 2020, the Company recorded an increase through stockholders' equity to the carrying value of its investment in Rattler LLC. A corresponding adjustment to the noncontrolling interest resulted in a decrease in Rattler's deferred tax liability related to its investment in Rattler LLC and a total net deferred tax asset balance for Rattler. Rattler incurred an NOL in the current year due principally to Rattler LLC's tax deductions for accelerated depreciation, which exceeded its other items of taxable income. At December 31, 2020, Rattler has federal net operating loss carryforwards of approximately $75 million which may be carried forward indefinitely to offset future taxable income.

Management considers the likelihood that Rattler's NOLs and other deferred tax attributes will be utilized prior to their expiration, if applicable. At December 31, 2020, Rattler's assessment included consideration of all available positive and negative evidence, including Rattler's projected future taxable income and the anticipated timing of reversal of deferred tax assets. As a result of the assessment, management determined that it is more likely than not that Rattler will realize its deferred tax assets as of December 31, 2020.

The following table sets forth changes in the Company's unrecognized tax benefits:

	December 31,	
	2020	2019
	(in millions)	
Balance at beginning of year	$ 7	$ 7
Increase resulting from prior period tax positions	—	—
Increase resulting from current period tax positions	—	—
Balance at end of year	7	7
Less: Effects of temporary items	(5)	(5)
Total that, if recognized, would impact the effective income tax rate as of the end of the year	$ 2	$ 2

The Company recognizes the tax benefit from a tax position only if it is more likely than not that it will be sustained upon examination by the taxing authorities, based upon the technical merits of the position. During the year ended December 31, 2020, the statute of limitations related to an uncertain tax position of the Company expired, and upon expiration the Company recognized tax benefit of $0.3 million and recorded a reduction to interest expense of less than $0.1 million. The Company's federal and state income tax returns for 2012 through the current tax year remain open and subject to examination by the IRS and major state taxing jurisdictions. Energen is currently under IRS examination of its federal consolidated income tax returns for 2014 and 2016. Accordingly, it is reasonably possible that significant changes to the reserve for uncertain tax positions may occur as a result of various audits and the expiration of the statute of limitations. Although the timing and outcome of tax examinations is highly uncertain, the Company does not expect the change in unrecognized tax benefit within the next 12 months would have a material impact to the financial statements.

The Company is continuing its practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the years ended December 31, 2020 and 2019, there was less than $0.2 million of interest and no penalties related to each period associated with uncertain tax positions recognized in the Company's consolidated financial statements.

15. DERIVATIVES

All derivative financial instruments are recorded at fair value in the accompanying balance sheet. 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 consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

Commodity Contracts

The Company has entered into multiple crude oil, natural gas, natural gas liquids and diesel fuel derivatives, indexed to the respective indices as noted in the table below, to reduce price volatility associated with certain of its oil and natural gas sales.

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 December 31, 2020, the Company had the following outstanding derivative contracts. When aggregating multiple contracts, the weighted average contract price is disclosed:

					Swaps		Collars	
Settlement Month	Settlement Year	Type of Contract	Bbls/Mmbtu/Gallons Per Day	Index	Weighted Average Differential	Weighted Average Fixed Price	Weighted Average Floor Price	Weighted Average Ceiling Price
OIL								
Jan. - Mar.	2021	Costless Collars	37,000	WTI Cushing	$—	$—	$34.95	$45.17
Apr. - June	2021	Costless Collars	15,000	WTI Cushing	$—	$—	$33.00	$45.33
July - Dec.	2021	Costless Collars	10,000	WTI Cushing	$—	$—	$30.00	$43.05
Jan. - June	2021	Roll Hedge(2)	12,000	WTI	$(0.07)	$—	$—	$—
Jan. - Mar.	2021	Swaps	5,000	WTI	$—	$45.46	$—	$—
Apr. - June	2021	Swaps	2,000	WTI	$—	$47.35	$—	$—
Jan. - June	2021	Basis Swap	8,000	WTI Midland(1)	$0.52	$—	$—	$—
Jan. - Dec.	2021	Swaps	5,000	WTI Houston Argus	$—	$37.78	$—	$—
Jan. - Dec.	2021	Swaps	5,000	Brent	$—	$41.62	$—	$—
Jan. - Mar.	2021	Costless Collars	82,000	Brent	$—	$—	$39.04	$48.51
Apr. - June	2021	Costless Collars	80,000	Brent	$—	$—	$39.26	$48.62
Jul. - Dec.	2021	Costless Collars	60,000	Brent	$—	$—	$39.43	$48.12
Jul. - Dec.	2021	Swaptions	5,000	Brent	$—	$51.00	$—	$—
NATURAL GAS								
Jan. - Dec.	2021	Swaps	200,000	Henry Hub	$—	$2.65	$—	$—
Jan. - Dec.	2021	Basis Swaps	230,000	Waha Hub(1)	$(0.69)	$—	$—	$—
Jan. - Dec.	2022	Basis Swaps	100,000	Waha Hub(1)	$(0.42)	$—	$—	$—

(1) The Company has fixed price basis swaps for the spread between the Cushing crude oil price and the Midland WTI crude oil price as well as the spread between the Henry Hub natural gas price and the Waha Hub natural gas price. The weighted average differential represents the amount of reduction to Cushing, Oklahoma, oil price and the Waha Hub natural gas price for the notional volumes covered by the basis swap contracts.
(2) The Company has rolling hedge basis swaps for the differential between the NYMEX prices between the calendar month average and the physical crude oil delivery month. The weighted average differential represents the amount of reduction to Cushing, Oklahoma, oil price for the notional volumes covered by the rolling hedge basis swap contracts.

Settlement Month	Settlement Year	Type of Contract	Bbls/Mcf Per Day	Index	Put Price
OIL					
Jan. - Dec.	2022	Option	5,000	Brent	$35.00

Interest Rate Swaps

The Company currently uses interest rate swaps to reduce the Company's exposure to variable rate interest payments associated with the Company's revolving credit facility. The interest rate swaps have not been designated as hedging instruments and as a result, the Company recognizes all changes in fair value immediately in earnings.

Type	Effective Date	Contractual Termination Date	Notional Amount (in millions)	Interest Rate
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.692 %
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.8361 %
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.852 %
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.722 %

See Note 18—Subsequent Events for discussion of derivative transactions which occurred subsequent to December 31, 2020.

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, including any deferred premiums, that are with the same counterparty and are subject to contractual terms which provide for net settlement. See Note 16—Fair Value Measurements for further details.

Gains and Losses on Derivative Instruments

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:

	Year Ended December 31,		
	2020	2019	2018
	(in millions)		
Gain (loss) on derivative instruments, net			
Commodity contracts	$ (32)	$ (151)	$ 101
Interest rate swaps	(49)	43	—
Total	$ (81)	$ (108)	$ 101
Net cash received (paid) on settlements			
Commodity contracts(1)	250	37	(121)
Interest rate swaps(2)	—	43	—
Total	$ 250	$ 80	$ (121)

(1) The year ended December 31, 2020 includes cash received on commodity contracts terminated prior to their contractual maturity of $17 million.
(2) The year ended December 31, 2019 includes cash received on interest rate swap contracts terminated prior to their contractual maturity of $43 million.

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 in Note 2—Summary of Significant Accounting Policies.

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 Viper's investment. Viper measured its previously outstanding investment, which was included in other assets on the consolidated balance sheet at December 31, 2019, utilizing the fair value option, and as such the investment was classified as Level 1 in the fair value hierarchy. The fair values of the Company's derivative contracts 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 (i) fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis, (ii) the gross amounts of recognized derivative assets and liabilities, (iii) the amounts offset under master netting arrangements with counterparties, and (iv) the resulting net amounts presented in the Company's consolidated balance sheets as of December 31, 2020 and December 31, 2019. The net amounts of derivative instruments are classified as current or noncurrent based on their anticipated settlement dates.

	As of December 31, 2020					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
	(in millions)					
Assets:						
Current:						
Derivative Instruments	$ —	$ 43	$ —	$ 43	$ (42)	$ 1
Non-current:						
Derivative Instruments	$ —	$ 187	$ —	$ 187	$ (187)	$ —
Liabilities:						
Current:						
Derivative Instruments	$ —	$ 291	$ —	$ 291	$ (42)	$ 249
Non-current:						
Derivative Instruments	$ —	$ 244	$ —	$ 244	$ (187)	$ 57

	As of December 31, 2019					
	Level 1	Level 2	Level 3	Total Gross Fair Value	Gross Amounts Offset in Balance Sheet	Net Fair Value Presented in Balance Sheet
	(in millions)					
Assets:						
Current:						
Derivative Instruments	$ —	$ 64	$ —	$ 64	$ (18)	$ 46
Non-current:						
Investment	$ 19	$ —	$ —	$ 19	$ —	$ 19
Derivative Instruments	$ —	$ 7	$ —	$ 7	$ —	$ 7
Liabilities:						
Current:						
Derivative Instruments	$ —	$ 45	$ —	$ 45	$ (18)	$ 27

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:

	December 31, 2020		December 31, 2019	
	Carrying Value(1)	Fair Value	Carrying Value(1)	Fair Value
	(in millions)			
Debt:				
Revolving credit facility	$ 23	$ 23	$ 13	$ 13
4.625% Notes due 2021	$ 191	$ 193	$ 399	$ 411
7.320% Medium-term Notes, Series A, due 2022	$ 21	$ 22	$ 21	$ 22
2.875% Senior Notes due 2024	$ 993	$ 1,053	$ 992	$ 1,012
4.750% Senior Notes due 2025	$ 496	$ 565	$ —	$ —
5.375% Senior Notes due 2025	$ 799	$ 824	$ 799	$ 840
3.250% Senior Notes due 2026	$ 793	$ 857	$ 792	$ 812
7.350% Medium-term Notes, Series A, due 2027	$ —	$ —	$ 11	$ 12
7.125% Medium-term Notes, Series B, due 2028	$ 107	$ 119	$ 108	$ 116
3.500% Senior Notes due 2029	$ 1,187	$ 1,286	$ 1,186	$ 1,226
Viper revolving credit facility	$ 84	$ 84	$ 97	$ 97
Viper's 5.375% Senior Notes due 2027	$ 472	$ 501	$ 490	$ 521
Rattler revolving credit facility	$ 79	$ 79	$ 424	$ 424
Rattler's 5.625% Senior Notes due 2025	$ 491	$ 528	$ —	$ —
DrillCo Agreement	$ 79	$ 79	$ 39	$ 39

(1) The carrying value includes associated deferred loan costs and any remaining discount or premium.

The fair values of the revolving credit facility, the Viper credit agreement and the Rattler credit agreement approximate their carrying values 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 values of the outstanding notes were determined using the December 31, 2020 quoted market prices, a Level 1 classification in the fair value hierarchy.

Fair Value of Financial Assets

The carrying amount of cash and cash equivalents, receivables, funds held for escrow, prepaid expenses and other current assets, payables and other accrued liabilities approximate their fair value because of the short-term nature of the instruments.

17. COMMITMENTS AND CONTINGENCIES

The Company is a party to various legal proceedings, disputes and claims arising in the course of its business, including those that arise from interpretation of federal and state laws and regulations affecting the crude oil and natural gas industry. While the ultimate outcome of the pending proceedings, disputes or claims, and any resulting impact on the Company, cannot be predicted with certainty, the Company's management believes that none of these matters, if ultimately decided adversely, will have a material adverse effect on the Company's financial condition, results of operations or cash flows. The Company's assessment is based on information known about the pending matters and its experience in contesting, litigating and settling similar matters. Actual outcomes could differ materially from the Company's assessment. The Company records reserves for contingencies related to outstanding legal proceedings, disputes or claims when information available indicates that a loss is probable, and the amount of the loss can be reasonably estimated.

Commitments

The following is a schedule of minimum future payments with commitments that have initial or remaining noncancelable terms in excess of one year as of December 31, 2020:

Year Ending December 31,	Transportation Commitments(1)	Sand Supply Agreement(2)	Produced Water Disposal Commitments(3)
		(in millions)	
2021	$ 60	$ 18	$ 5
2022	60	18	5
2023	51	18	5
2024	48	18	5
2025	47	18	5
Thereafter	133	5	31
Total	$ 399	$ 95	$ 56

(1) The Company has committed to transport gross quantities of crude oil on various pipelines under a variety of contracts including throughput and take-or-pay agreements. The Company's failure to purchase the minimum level of quantities would require it to pay shortfall fees up to the amount of the original monthly commitment amounts included in the table above.
(2) The Company has committed to purchase minimum quantities of sand for use in its drilling operations. Our failure to purchase the minimum level of quantities would require us to pay shortfall fees up to the commitment amounts included in the table above.
(3) Rattler entered into a minimum volume commitment to purchase produced water disposal services under a 14 year agreement beginning in 2021.

At December 31, 2020, the Company's delivery commitments covered the following gross volumes of oil:

Year Ending December 31,	Oil Volume Commitments (Bbl/d)
2021	175,000
2022	175,000
2023	175,000
2024	125,000
2025	125,000
Thereafter	400,000
Total	1,175,000

As of December 31, 2020, Rattler's anticipated future capital commitments for its equity method investments total $72 million in the aggregate. The timing of when capital commitments will be requested can vary, but at December 31, 2020, approximately $57 million of the remaining commitment is expected to be funded in 2021, $7 million in 2022 and $8 million in 2023.

18. SUBSEQUENT EVENTS

Announced Acquisition of QEP Resources

On December 21, 2020, the Company announced a definitive agreement to acquire QEP Resources Inc. ("QEP") in an all-stock transaction valued at $2.2 billion including QEP's net debt of $1.6 billion as of September 30, 2020 based upon closing share prices on October 16, 2020. The consideration will consist of 0.050 shares of Diamondback common stock for each share of QEP common stock, representing an implied value to each QEP stockholder of $2.29 per share based on the closing price of Diamondback common stock on December 18, 2020. The transaction was unanimously approved by the Board of Directors of each company. The transaction is anticipated to close shortly following the special meeting of QEP Stockholders, which is scheduled for March 16, 2021, subject to QEP stockholder approval and other customary closing conditions. See Item 1A. "Risk Factors" for further discussion of risks related to the QEP acquisition.

Announced Acquisition of Guidon Operating LLC

On December 21, 2020, the Company announced a definitive purchase agreement to acquire all leasehold interests and related assets of Guidon Operating LLC ("Guidon") in exchange for 10.6 million shares of Diamondback common stock and $375 million of cash. In accordance with the terms of the purchase agreement, the Company deposited $50 million into an escrow account in December 2020, which will be released to Guidon upon the closing of the transaction. The cash portion of this transaction is expected to be funded through a combination of cash on hand and borrowings under the Company's credit facility. The transaction is anticipated to close on February 26, 2021.

Fourth Quarter 2020 Dividend Declaration

On February 18, 2021, the Board of Directors of the Company declared a cash dividend for the fourth quarter of 2020 of $0.40 per share of common stock, payable on March 11, 2021 to its stockholders of record at the close of business on March 4, 2021.

Commodity Contracts

Subsequent to December 31, 2020, the Company entered into new fixed price swaps and basis swaps, costless collars and roll hedges. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges noted in the table below. When aggregating multiple contracts, the weighted average contract price is disclosed. The following table presents the derivative contracts entered into by the Company between January 1, 2021 and February 19, 2021:

					Swaps		Collars	
Settlement Month	**Settlement Year**	**Type of Contract**	**Bbls/Mmbtu Per Day**	**Index**	**Weighted Average Differential**	**Weighted Average Fixed Price**	**Weighted Average Floor Price**	**Weighted Average Ceiling Price**
OIL								
July - Sep.	2021	Costless Collar	2,000	WTI	$—	$—	$45.00	$52.30
Oct. - Dec.	2021	Costless Collar	9,000	WTI	$—	$—	$45.00	$59.22
July - Sep.	2021	Costless Collar	5,000	WTI Houston Argus	$—	$—	$45.00	$57.90
Apr. - Sep.	2021	Costless Collar	2,000	IPE Brent	$—	$—	$45.00	$57.72
Oct. - Dec.	2021	Costless Collar	4,000	IPE Brent	$—	$—	$45.00	$60.64
Mar. - Dec.	2021	Roll Hedge(2)	25,000	WTI	$0.32	$—	$—	$—
Mar. - Dec.	2021	Swap	20,000	Henry Hub	$—	$2.95	$—	$—
Jan. - June	2021	Basis Swap	15,000	WTI Midland(1)	$0.95	$—	$—	$—
July - Dec.	2021	Basis Swap	18,000	WTI Midland(1)	$0.93	$—	$—	$—
Jan. - Mar.	2022	Costless Collar	18,000	IPE Brent	$—	$—	$45.00	$61.35
Apr. - Dec.	2022	Costless Collar	2,000	IPE Brent	$—	$—	$45.00	$60.00
NATURAL GAS								
Apr. - Dec.	2021	Basis Swap	20,000	Waha Hub(1)	$(0.255)	$—	$—	$—
Jan. - Dec.	2022	Basis Swap	30,000	Waha Hub(1)	$(0.34)	$—	$—	$—
NATURAL GAS LIQUIDS								
Feb. - Dec.	2021	Swap	84,000	Mont Belvieu	$—	$0.70	$—	$—

(1) The Company has fixed price basis swaps for the spread between the WTI Midland crude oil price and the NYMEX WTI crude oil price as well as the spread between the Waha Hub natural gas price and the Henry Hub natural gas price. The weighted average differential represents the amount of reduction to Cushing, Oklahoma oil price and the Waha Hub natural gas price for the notional volumes covered by the basis swap contracts.
(2) The Company has rolling hedge basis swaps for the differential between the NYMEX prices between the calendar month average and the physical crude oil delivery month. The weighted average differential represents the amount of reduction to Cushing, Oklahoma oil price for the notional volumes covered by the rolling hedge basis swap contracts.

Interest Rate Swaps

The following table presents the interest rate swap contracts terminated by the Company between January 1, 2021 and February 19, 2021:

Type	**Effective Date**	**Contractual Termination Date**	**Notional Amount (in millions)**	**Interest Rate**
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.8361 %
Interest Rate Swap	December 31, 2024	December 31, 2054	$ 250	1.852 %

19. SEGMENT INFORMATION

The Company reports its operations in two operating segments: (i) the upstream segment, which is engaged in the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves primarily in the Permian Basin in West Texas and (ii) the midstream operations segment, which includes midstream services and real estate operations. All of the Company's equity method investments are included in the midstream operations segment. The segments comprise the structure used by its Chief Operating Decision Maker ("CODM") to make key operating decisions and assess performance.

The following tables summarize the results of the Company's operating segments during the periods presented:

	Upstream	Midstream Operations	Eliminations	Total
	(in millions)			
Year Ended December 31, 2020:				
Third-party revenues	$ 2,756	$ 57	$ —	$ 2,813
Intersegment revenues	—	367	(367)	—
Total revenues	$ 2,756	$ 424	$ (367)	$ 2,813
Lease operating expenses	$ 425	$ —	$ —	$ 425
Depreciation, depletion and amortization	$ 1,251	$ 53	$ —	$ 1,304
Impairment of oil and natural gas properties	$ 6,021	$ —	$ —	$ 6,021
Income (loss) from operations	$ (5,562)	$ 182	$ (96)	$ (5,476)
Interest expense, net	$ (180)	$ (17)	$ —	$ (197)
Other income (expense)	$ (87)	$ (10)	$ (6)	$ (103)
Provision for (benefit from) income taxes	$ (1,114)	$ 10	$ —	$ (1,104)
Net income (loss) attributable to non-controlling interest	$ (190)	$ 35	$ —	$ (155)
Net income (loss) attributable to Diamondback Energy, Inc.	$ (4,525)	$ 110	$ (102)	$ (4,517)
Total assets	$ 16,128	$ 1,809	$ (318)	$ 17,619

	Upstream	Midstream Operations	Eliminations	Total
	(in millions)			
Year Ended December 31, 2019:				
Third-party revenues	$ 3,891	$ 73	$ —	$ 3,964
Intersegment revenues	—	375	(375)	—
Total revenues	$ 3,891	$ 448	$ (375)	$ 3,964
Lease operating expenses	$ 490	$ —	$ —	$ 490
Depreciation, depletion and amortization	$ 1,405	$ 42	$ —	$ 1,447
Impairment of oil and natural gas properties	$ 790	$ —	$ —	$ 790
Income (loss) from operations	$ 790	$ 219	$ (314)	$ 695
Interest expense, net	$ (171)	$ (1)	$ —	$ (172)
Other income (expense)	$ (149)	$ (6)	$ (6)	$ (161)
Provision for (benefit from) income taxes	$ 21	$ 26	$ —	$ 47
Net income (loss) attributable to non-controlling interest	$ 75	$ 91	$ (91)	$ 75
Net income (loss) attributable to Diamondback Energy, Inc.	$ 374	$ 95	$ (229)	$ 240
Total assets	$ 22,125	$ 1,636	$ (230)	$ 23,531

	Upstream	Midstream Operations	Eliminations	Total
	(in millions)			
Year Ended December 31, 2018:				
Third-party revenues	$ 2,132	$ 44	$ —	$ 2,176
Intersegment revenues	—	140	(140)	—
Total revenues	$ 2,132	$ 184	$ (140)	$ 2,176
Lease operating expenses	$ 205	$ —	$ —	$ 205
Depreciation, depletion and amortization	$ 598	$ 25	$ —	$ 623
Income (loss) from operations	$ 1,071	$ 80	$ (140)	$ 1,011
Interest expense, net	$ (87)	$ —	$ —	$ (87)
Other income (expense)	$ 189	$ —	$ —	$ 189
Provision for (benefit from) income taxes	$ 151	$ 17	$ —	$ 168
Net income (loss) attributable to non-controlling interest	$ 99	$ —	$ —	$ 99
Net income (loss) attributable to Diamondback Energy, Inc.	$ 923	$ 63	$ (140)	$ 846
Total assets	$ 21,096	$ 604	$ (104)	$ 21,596

20. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Company's oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are as follows:

	December 31, 2020	December 31, 2019
	(In millions)	
Oil and natural gas properties:		
Proved properties	$ 19,884	$ 16,575
Unproved properties	7,493	9,207
Total oil and natural gas properties	27,377	25,782
Accumulated depletion	(4,237)	(2,995)
Accumulated impairment	(7,954)	(1,934)
Net oil and natural gas properties capitalized	$ 15,186	$ 20,853

Costs incurred in oil and natural gas activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows:

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Acquisition costs:			
Proved properties	$ 13	$ 194	$ 5,665
Unproved properties	106	418	5,818
Development costs	381	956	493
Exploration costs	1,098	1,915	1,090
Total	$ 1,598	$ 3,483	$ 13,066

Results of Operations from Oil and Natural Gas Producing Activities

For revenues and expenses related to the production and sale of oil, natural gas and natural gas liquids, see the results of the Company's upstream business segment in Note 19—Segment Information.

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2020, 2019 and 2018 were prepared by Ryder Scott Company, L.P., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The changes in estimated proved reserves are as follows:

	Oil (MBbls)	Natural Gas Liquids (MBbls)	Natural Gas (MMcf)
Proved Developed and Undeveloped Reserves:			
As of December 31, 2017	233,181	54,609	285,369
Extensions and discoveries	143,256	33,152	154,088
Revisions of previous estimates	3,689	11,138	3,642
Purchase of reserves in place	281,333	98,865	640,761
Divestitures	(156)	(8)	(543)
Production	(34,367)	(7,465)	(34,668)
As of December 31, 2018	626,936	190,291	1,048,649
Extensions and discoveries	256,569	66,572	318,874
Revisions of previous estimates	(84,789)	(8,166)	(149,657)
Purchase of reserves in place	13,974	3,813	19,830
Divestitures	(33,269)	(3,809)	(21,272)
Production	(68,518)	(18,498)	(97,613)
As of December 31, 2019	710,903	230,203	1,118,811
Extensions and discoveries	191,009	58,410	316,035
Revisions of previous estimates	(78,244)	21,927	300,160
Purchase of reserves in place	2,124	778	3,512
Divestitures	(209)	(141)	(905)
Production	(66,182)	(21,981)	(130,549)
As of December 31, 2020	759,401	289,196	1,607,064
Proved Developed Reserves:			
December 31, 2017	141,246	35,412	190,740
December 31, 2018	403,051	125,509	705,084
December 31, 2019	457,083	165,173	824,760
December 31, 2020	443,464	192,495	1,085,035
Proved Undeveloped Reserves:			
December 31, 2017	91,935	19,198	94,629
December 31, 2018	223,885	64,782	343,565
December 31, 2019	253,820	65,030	294,051
December 31, 2020	315,937	96,701	522,029

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

During the year ended December 31, 2020, the Company's extensions and discoveries of 302,092 MBOE resulted primarily from the drilling of 682 new wells and from 298 new proved undeveloped locations added. Viper royalty interests accounted for 8% of the extension volumes. The Company's downward revisions of previous estimates of 6,290 MBOE were the result of negative revisions due to lower product pricing of 54,645 MBOE, which were partially offset by positive revisions of 23,066 MBOE associated with a reduction in lease operating expenses, resulting in a total negative pricing revision of 31,579 MBOE. Downgrades of 31,074 MBOE are primarily from changes in the corporate development plan. These revisions were offset by positive performance revisions of 56,362 MBOE associated with less gas flaring and a corresponding increase in natural gas liquid recoveries.

Diamondback Energy, Inc. and Subsidiaries
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During the year ended December 31, 2019, the Company's extensions and discoveries totaling 376,287 MBOE resulted primarily from the drilling of 283 new wells and from 291 new proved undeveloped locations added. Viper royalty interests accounted for 5% of the extension volumes. The Company's downward revisions of 117,898 MBOE were the result of proved undeveloped downgrades associated with inventory refinement following the Energen acquisition along with updated development plans and lower realized prices. Purchases of 21,092 MBOE were the result of 10,939 MBOE of working interest purchases and 10,153 MBOE of Viper royalty purchases, excluding mineral interests dropped down to Viper.

During the year ended December 31, 2018, the Company's extensions and discoveries of 202,089 MBOE resulted primarily from the drilling of 135 new wells and from 138 new proved undeveloped locations added in which the Company owns a working interest. Viper royalty interests accounted for 10% of the extension volumes. The Company's revisions of previous estimates were primarily the result of positive technical and performance revisions of 14,218 MBOE, upward revisions of 6,032 MBOE due to higher pricing and downward revisions of 4,815 MBOE from PUD reclassifications due to timing. Purchases of 486,992 MBOE were the result of 477,686 MBOE of working interest purchases, primarily attributable to Energen, and 9,306 MBOE of Viper royalty purchases.

At December 31, 2020, the Company's estimated PUD reserves were approximately 499,643 MBOE, a 131,784 MBOE increase over the reserve estimate at December 31, 2019 of 367,859 MBOE. The following table includes the changes in PUD reserves for 2020 (MBOE):

Beginning proved undeveloped reserves at December 31, 2019	367,859
Undeveloped reserves transferred to developed	(89,133)
Revisions	(15,742)
Purchases	964
Divestitures	(14)
Extensions and discoveries	235,709
Ending proved undeveloped reserves at December 31, 2020	499,643

The increase in proved undeveloped reserves was primarily attributable to extensions of 220,023 MBOE from 277 gross (236 net) wells in which the Company has a working interest and 15,686 MBOE from 299 gross wells in which Viper owns royalty interests. Of the 277 gross working interest wells, 98 were in the Delaware Basin. Transfers of 89,133 MBOE were the result of drilling or participating in 102 gross (94 net) horizontal wells in which the Company has a working interest and 82 gross wells in which the Company has a royalty interest or mineral interest through Viper. The Company owns a working interest in 78 of the 82 gross Viper wells. Downward revisions of 15,742 MBOE were the result of (i) negative revisions of 4,226 MBOE due to lower product pricing, which were partially offset by positive revisions of 1,494 MBOE associated with a reduction in lease operating expenses, resulting in a total negative pricing revision of 2,732 MBOE, and (ii) PUD downgrades of 26,329 MBOE primarily from changes in the corporate development plan. These revisions were offset with positive performance revisions of 13,319 MBOE associated with less gas flaring and a corresponding increase in shrunk gas and natural gas liquid recoveries.

As of December 31, 2020, all of the Company's proved undeveloped reserves are planned to be developed within five years from the date they were initially recorded. During 2020, approximately $381 million in capital expenditures went toward the development of proved undeveloped reserves, which includes drilling, completion and other facility costs associated with developing proved undeveloped wells.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is based on the unweighted average, first-day-of-the-month price. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved oil and natural gas reserves as of December 31, 2020, 2019 and 2018.

	December 31,		
	2020	2019	2018
	(In millions)		
Future cash inflows	$ 32,173	$ 40,681	$ 43,578
Future development costs	(3,585)	(3,809)	(3,560)
Future production costs	(10,763)	(9,319)	(7,727)
Future production taxes	(2,354)	(2,905)	(2,935)
Future income tax expenses	(727)	(2,635)	(3,913)
Future net cash flows	14,744	22,013	25,443
10% discount to reflect timing of cash flows	(7,986)	(11,829)	(13,767)
Standardized measure of discounted future net cash flows(1)	$ 6,758	$ 10,184	$ 11,676

(1) Includes $1.0 billion, $1.3 billion, and $1.1 billion, for the years ended December 31, 2020, 2019 and 2018, respectively, attributable to the Company's consolidated subsidiary, Viper, in which there is a 42% non-controlling interest at December 31, 2020.

The table below presents the unweighted arithmetic average first-day-of–the-month price for oil, natural gas and natural gas liquids utilized in the computation of future cash inflows.

	December 31,		
	2020	2019	2018
Oil (per Bbl)	$ 38.06	$ 51.88	$ 59.63
Natural gas (per Mcf)	$ 0.09	$ 0.18	$ 1.47
Natural gas liquids (per Bbl)	$ 10.83	$ 15.65	$ 24.43

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows:

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Standardized measure of discounted future net cash flows at the beginning of the period	$ 10,184	$ 11,676	$ 3,757
Sales of oil and natural gas, net of production costs	(2,225)	(3,334)	(1,786)
Acquisitions of reserves	30	309	5,520
Divestitures of reserves	(4)	(500)	(2)
Extensions and discoveries, net of future development costs	1,514	4,004	3,287
Previously estimated development costs incurred during the period	704	120	535
Net changes in prices and production costs	(5,273)	831	1,805
Changes in estimated future development costs	526	(3,190)	(81)
Revisions of previous quantity estimates	(462)	(1,242)	271
Accretion of discount	1,126	1,344	380
Net change in income taxes	807	693	(1,728)
Net changes in timing of production and other	(169)	(527)	(282)
Standardized measure of discounted future net cash flows at the end of the period	$ 6,758	$ 10,184	$ 11,676